COUNTDOWN ACID RAIN

FUTURE ABATEMENT STRATEGIES

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SUMMARY REPORT

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COUNTDOWN ACID RAIN

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Summary Report

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DISCLAIMER

The conclusions, opinions and recommendations expressed in this report are those of the consultant and do not necessarily represent the views of the Ontario Ministry of the Environment. In addition, the consultant is solely responsible for the accuracy of data and estimates presented in this report.

FOREWORD

This report presents a study of SO_2 and NO_x emission sources in Ontario and proposed emission control strategies to achieve further reductions of SO_2 and NO_x after 1993. The report consists of a summary document supported by three appendices.

Summary	The summary document describes the findings of 3 phases of the study and draws conclusions on abatement strategies.
Appendix 1	The Phase 1 Report sets out a 1985 base year emission inventory for SO_2 and NO_x, examines past trends, and outlines five basic future scenarios.
Appendix 2	The Phase II Report identifies the costs of reducing SO_2 and NO_x using alternative emission control technologies required to meet the emission targets identified in the Phase I Report.
Appendix 3	The Phase III Report develops alternative cost-effective abatement strategies that achieve pre-specified aggregate emission targets. The computer model developed for the foregoing work is described.
This Document	**This document describes the Summary.**

Summary Report

Countdown Acid Rain
Future Abatement Strategies

to control emissions that cause acid rain

The overall objective of this study is to evaluate the cost effectiveness of alternative emission control technologies for sulphur dioxide (SO_2) and nitrogen oxides (NO_x) emissions in Ontario. This study is an initial examination which points the way to further investigations. It is part of a larger effort by the Government of Ontario to determine how and where to control emissions that cause acid rain and other damaging effects.

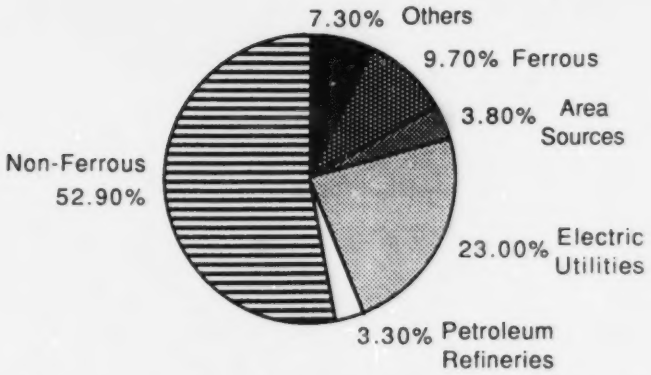
4 reports

Four reports make up the documentation for this study. The "Phase 1 Report" sets out a 1985 emission inventory for SO_2 and NO_x by major point sources, industrial sectors and area sources. The "Phase 2 Report" identifies the costs and contaminant removal capabilities of alternative emission control technologies. The "Phase 3 Report" outlines alternative cost effective abatement strategies and sets out the user-friendly modelling framework for changing the assumptions and allowing for technological changes. This "Summary Report" presents an overview of findings contained in the preceding documents, draws conclusions and recommends an implementation plan.

4 major SO_2 Emitters

In 1985 SO_2 emissions in Ontario totaled 1.458 million tonnes. Of this volume non-ferrous smelters contributed 53 per cent followed by electric utilities at 23 per cent, ferrous smelters at 10 per cent and area sources at 4 per cent (refer to Figure 1).

Figure 1
Total SO_2 Emission Sources
1985



The 15 largest SO_2 point source emitters are set out in Table 1. Of these INCO, Ontario Hydro, Algoma Ore and Falconbridge stand out as the dominant emitters and among these INCO is the leader by a wide margin.

Table 1
15 Major Point Sources of SO2 in Ontario
(1985)

	Tonnes/Year
INCO (Sudbury)	695,008
Ontario Hydro	336,633
Algoma (Wawa)	115,890
Falconbridge (Sudbury)	74,352
Imperial Oil (Sarnia)	19,595
Shell Canada (Corruna)	16,103
Lake Ontario Cement (Picton)	7,748
Algoma (Sault Ste. Marie)	7,419
Stelco (Nanticoke)	6,920
Courtauld's Canada Ltd. (Cornwall)	6,517
Petrosar Ltd. (Corruna)	6,260
James River Marathon (Marathon)	6,225
Texaco Canada (Nanticoke)	6,210
Dofasco Inc. (Hamilton)	6,126
Kerr Addison (Virginiatown)	5,144
	1,316,150

The largest area emitters as illustrated below are vehicles and industrial/commercial heating. Together they emit 3.80 per cent of the total SO_2 in Ontario.

Figure 2
SO_2 Area Sources
1985

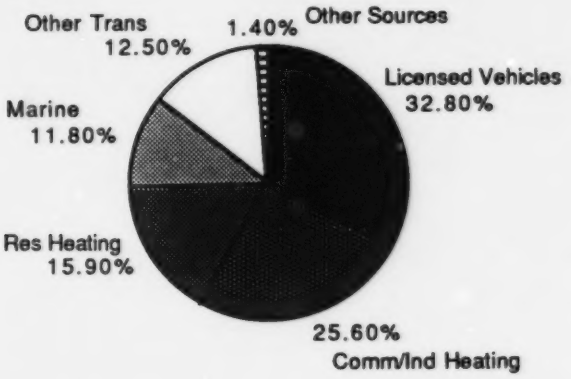
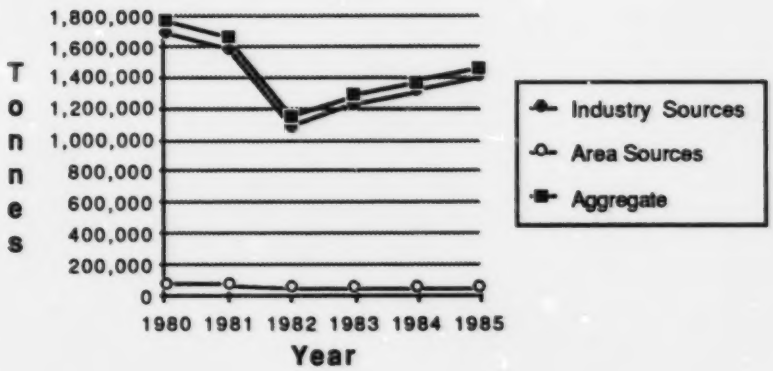


Figure 3 shows that between 1980 and 1985 SO_2 emissions from industrial sources declined by 17 per cent while emissions from area sources fell by 29 percent. The trend between 1982 and 1985 shows an increase in SO_2 emissions.

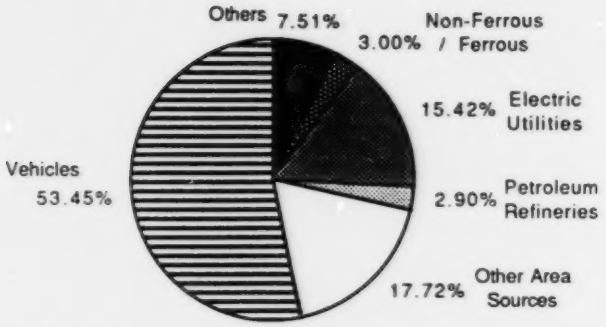
Figure 3
SO_2 Emissions Trends
1980-1985



area sources generate majority of anthropogenic NO_x

NO_x emissions in 1985 amounted to 612 kilotonnes. Of this total, transportation and area sources dominate at 71.1 per cent. Electric utilities are next at 15.4 per cent, followed by space heating at 6.8 per cent, non-ferrous / ferrous smelters at 3 per cent, refineries at 2.9 per cent, marine at 1.2 per cent and others at 7.5 per cent (refer to Figure 4).

Figure 4
Total NO_X Emission Sources
1985



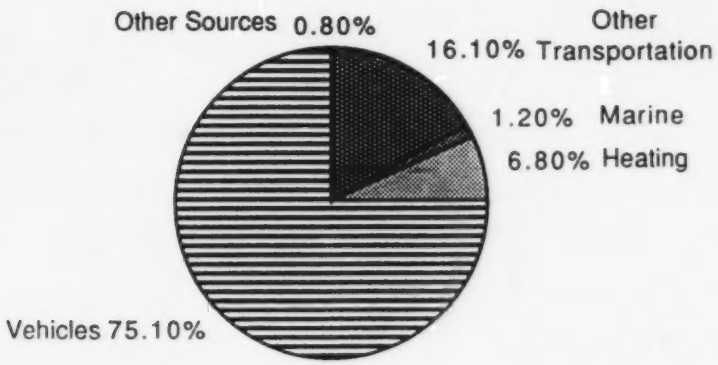
The 10 largest point source emitters for NO_X are identified in Table 2. Ontario Hydro is the dominant generator.

Table 2
10 Major Point Sources of NO_X in Ontario
1985

	Tonnes/Year
Ontario Hydro	94,437
Stelco (Hamilton)	5,567
Petrosar Ltd. (Corunna)	5,525
INCO (Sudbury)	4,893
Imperial Oil (Sarnia)	3,629
Algoma Steel Corp (Sault Ste. Marie)	3,207
Dow Chemical (Sarnia)	3,080
Esso Chemicals (Sarnia)	2,920
Stelco (Nanticoke)	2,602
Gulf Canada Ltd. (Mississauga)	2,238
	128,098

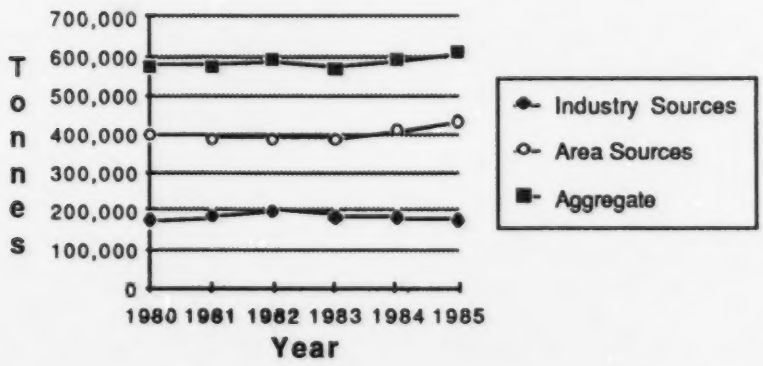
Among area sources, vehicles and other transportation account for 91.2 per cent of the emissions while heating accounts for 6.8 per cent, marine for 1.2 per cent and other sources for .8 per cent (refer to Figure 5).

Figure 5
NO_X Area Sources
1985



NO_X emissions between 1980 and 1985, from all sources as shown in Figure 5, revealed a decline of 2 per cent from industrial sources and a growth of 8.5 per cent from area sources. The aggregate emissions between 1980 and 1985 showed an increase of 5.3 per cent excluding emissions from forest fires.

Figure 6
NO_X Emission Trends
1980-1985



1994 emission targets specified for major point sources

In recognition of the serious environmental damage being caused by acid rain, the Government of Ontario recognized in 1985 that SO_2 and NO_x emissions must be reduced. Accordingly they encouraged all emitters to utilize abatement equipment and procedures and they legislated that the four major point sources, INCO, Ontario Hydro, Algoma and Falconbridge, must meet prescribed minimum emission limits for SO_2 and NO_x by 1994. These limits are set out below.

Table 3

Company	Regulation	1985 Emissions		1994 Emission Limits	
		SO2	NOx	SO2	SO2+NOx
		(Kilotonnes)		(Kilotonnes)	
INCO	660/85	695.0	4.9	265.0	-
Falconbridge	661/85	74.4	< 0.5*	100.0	-
Ontario Hydro	281/87	336.6	94.4	175.0	215
Algoma (Wawa)	663/85	115.9	0.3*	125.0	-

* Estimated

10 industrial sectors emit large quantities of SO_2 and NO_x

There are ten industrial sectors that give rise to the majority of SO_2 and 13.4 per cent of NO_x emissions. These are:

- Primary Metals
- Transportation Equipment *
- Non Metallic Mineral Products
- Chemicals and Chemical Products
- Food and Beverages
- Textile Industries
- Metal Fabricating
- Paper and Allied Products
- Others - includes municipal and sewage sludge incinerators, commercial enterprises and institutions such as hospitals and universities
- Rubber and Plastics - SO2 emissions only

* Does not not include vehicles

many potential abatement technologies but only a few are well proven

A wide variety of abatement technologies is available to control SO_2 and NO_x emissions. Thirty-eight systems were identified and discussed during the course of this study. In the end it was concluded that only a few were proven and acceptable. The other technologies may be used, but those examined in this study can serve as surrogates, setting benchmark costs which would be incurred. Chief among the systems examined for SO_2 were flue gas desulphurization, petroleum fuel desulphurization and fuel switching. For NO_x control, the preferred means of abatement included catalytic converters for mobile sources, and for point sources, low NO_x burners, lower excess air, selective non-catalytic reduction and selective catalytic reduction.

fuel desulphurization, fuel switching and flue gas desulphurization for SO_2

As the name implies petroleum fuel desulphurization is accomplished by lowering the sulphur content of fuel oils. Fuel switching as used in this study involves changing from coal and oil to natural gas. In the case of flue gas desulphurization there are two basic types of systems - wet and dry. Wet scrubbing systems absorb SO_2 from the gas stream into a slurry of an alkaline chemical forming a sulphate. The most widely used systems employ lime or limestone as the alkaline reactant. Dry scrubbing systems have not been used the same length of time as wet systems, but they are becoming prevalent with power utilities, industries and municipalities. In these systems, adsorption of SO_2 and other acid gases takes place when the flue gas comes in contact with a sprayed dry or slurry sorbent.

Sulphur dioxide emissions are primarily generated by general industry during the use of boilers and in some processes. In the case of boilers the means of emission abatement that hold most promise are flue gas desulphurization and fuel changing to low sulphur fuel oils or natural gas. Abatement of SO_2 emissions from industrial processes appears to be best accomplished through the use of flue gas desulphurization technologies.

low NO_x burners, lower excess air, selective non-catalytic and catalytic reduction for NO_x

Low NO_x burners are seen to hold significant promise as a means for reducing NO_x emissions. They are designed to control the air/fuel ratio in the burner area thereby retarding the formation of NO_x from fuel bound nitrogen. Lower excess air involves

reducing NO_X concentrations by lowering combustion air rates so that exhaust gases have a oxygen content of approximately 3 per cent. Both selective non-catalytic reduction and selective catalytic reduction are post combustion controls. The former reduces NO_X through the addition of ammonia and very high temperatures. The latter relies on ammonia in the presence of a catalyst to reduce NO_X to N_2 and water vapour.

Nitrogen oxide emissions generated by general industry through the use of boilers can best be controlled by making changes to fuel burners or by modifying the actual boiler furnace operations. In the latter case the most commonly used technology is low excess air which involves reducing the amount of air supplied to the burner system. In the case of production processes, NO_X abatement is best achieved through catalytic reduction technologies.

Small incremental fuel switching for NO_X is not usually carried out. However, when fuel is switched to reduce SO_2 by substituting natural gas there is a benefit in that lower NO_X emissions are produced as a result of the elimination of fuel nitrogen in the substituted natural gas.

catalytic convertors for mobile sources

NO_X emissions are dominated by mobile source emissions (which are now subject to Federal regulation). Control options are (1) a catalytic convertor required on new cars by federal regulation limiting emission to one gram of NO_X per mile and (2) a more efficient catalytic convertor that exceeds the federal requirement and reduces NO_X emissions to 0.4 grams per mile.

abatement controls considered by the model as illustrations for the 4 major point sources

The four major point sources have been investigating a variety of abatement options in order to exceed their prescribed emission limits by 1994. The following processes appear to hold the most promise.

Falconbridge does not currently exceed the 1994 target emission limits for either SO_2 or NO_X. According to the model used in this study further reductions are possible if separate streams of exhaust gases are treated by dry lime injection using a spray-dryer. Implementation of this form of abatement control could reduce annual SO_2 emissions by 50 kilotonnnes.

At INCO the remaining gas streams to be controlled involve a vast number of low strength sources. Despite what INCO is actually doing, for the purposes of this study it was assumed they could be controlled at a single emission point by limestone scrubbing and that a suitable location for the resulting limestone sludge could be found on the company property.

In the case of Algoma the abatement process that seems best suited to further lowering SO_2 emissions is wet flue gas desulphurization using limestone.

The most cost effective technology for controlling SO_2 from Ontario Hydro generating stations appears to be a high efficiency wet flue gas desulphurization process using limestone. NO_x emissions might be cost-effectively controlled by installing selective catalytic reduction units at suitable locations.

abatement controls: How effective? How costly?

The cost effectiveness of selected SO_2 and NO_x abatement technologies applied to the four major point sources and the nine significant industrial sectors are briefly explained below.

In their 1988 Progress Report, INCO estimates that an annual production of 240 million pounds of nickel will allow them to achieve their 1994 emission limit for SO_2. A further 10 percent reduction below this limit would involve an annualized cost of $752 per tonne of SO_2 removed (Appendix 2, Table 4-1). If a 50 per cent reduction is pursued, economies of scale come into play and an annualized cost of $362 per tonne of SO_2 removed would be incurred.

Ontario Hydro's coal and oil fired generating stations have a total rated generating capacity of 99.4 million megawatt hours per annum. Assuming full output from these stations, the utility would face an annualized cost per tonne of SO_2 removed of $848 if prescribed emission targets is exceeded by 10 per cent and $847 if it is surpassed by 50 per cent (source Appendix 2,Table 4-1). For NO_x the annualized amount would be approximately $446 per tonne in both cases (source Appendix 2, Table 4-3).

Based on a nickel production rate of 88 million pounds per year, Falconbridge will incur an annualized cost of $1,158 dollars per tonne for a further 10 per cent reduction

in SO_2 emissions and a $1,566 per tonne annualized cost for a further 50 per cent reduction (Appendix 2, Table 4-1) .

Based on approximately 1.0 million tonnes of iron ore sinter production per year, Algoma will incur an annualized cost of $110 per tonne of SO_2 removed given a 20 per cent reduction, and $835 for a 50 per cent reduction (Appendix 2, Table 4.1).

The annualized costs per tonne of SO_2 removed in the nine industrial sectors which are significant emitters of SO_2 and NO_x show a considerable range from one sector to another. For SO_2, costs range from $147 per tonne in the Chemical and Petroleum Products sector to $99,873 in Other Groups (source Appendix 2, Table 4-2). The corresponding figures for NO_x vary between annualized savings of $20,985 per tonne removed in the Non-Metallic Mineral Products sector to a cost of $21,551 per tonne in the Other Groups sector (Appendix 2, Table 4-4). Cost effectiveness considerations would lead firms to choose abatement technologies in the lower cost range of those indicated above. These cost effective technologies are discussed in the next section.

the implications of "what if for SO_2"

In order to determine the most cost-effective strategy for SO_2 abatement across all sectors and point sources, a series of "what if scenarios" was formulated and tested. Three scenarios examined the impact of different removal targets on the overall cost of SO_2 abatement strategies. The three emission reduction scenarios that were examined included lowering an existing 1994 base case emission target of 900,885 tonnes by 10, 30 and 50 per cent (scenarios 1,2,3 respectively).

It should be noted that Ontario will meet SO_2 emission limits of 885,000 tonnes per year in 1994. The higher value of 900,885 tonnes per year arises from the implicit assumption that Algoma Steel Corp. (Wawa) and Falconbridge will increase emissions to their maximum acceptable levels.

Four other scenarios looked at the effect on base case conditions given the unlikely event that either INCO or Ontario Hydro fail to meet their 1994 emission targets.

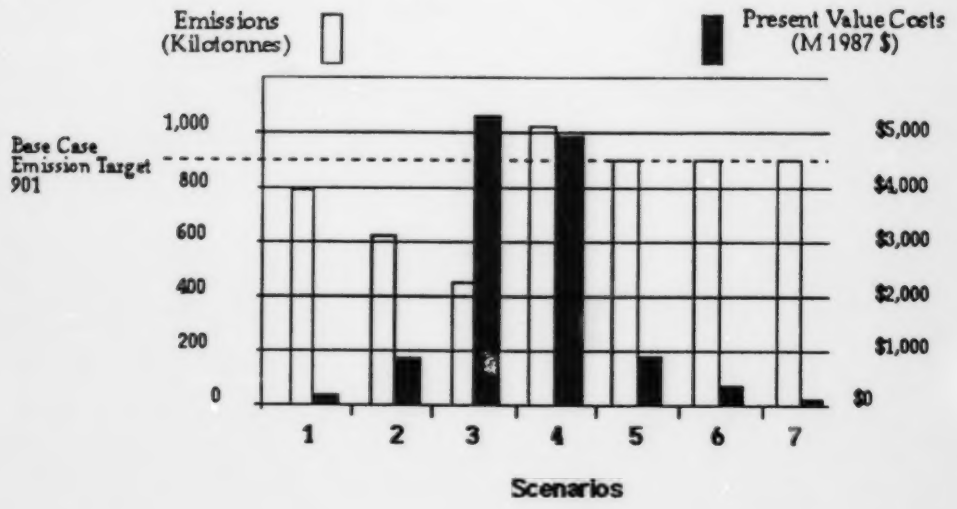
These scenarios included the following:

- INCO fails to meet the 1994 regulated target and remains at its 1985 emission level (Scenario 4).
- INCO only gets half way towards the 1994 regulated target (Scenario 5).

- Ontario Hydro fails to meet the 1994 regulated target and remains at its 1985 emission level (Scenario 6).
- Ontario Hydro only gets half way towards the 1994 regulated target (Scenario 7).

Figure 7 sets out the tonnes of SO_2 that would be emitted on an annual basis under each scenario. The same figure also shows the costs that would be incurred over 15 years to meet these emission levels.

Figure 7
Projected SO_2 Emission Levels and Associated Costs
For Alternative Scenarios
(Source: Appendix 3, Table 4.1-4.4)



Based on the data contained in Figure 7, it is apparent from the first three scenarios that there is a disproportionately higher cost associated with successively greater levels of emission control. Reducing SO_2 by 50 per cent from 1994 levels would cost 30 times more than reducing by 10 per cent from 1994 levels. Similarly going from a 30 per cent cut to a 50 per cent cut escalates control costs 6 times.

If INCO fails to reduce its emissions and remains at its 1985 emission level, maximum costs are imposed on all other emitters and overall abatement costs are 5.6 times beyond those incurred in Scenario 2 and the 1994 base case emission target is exceeded by 13 per cent. If INCO meets 50% of its 1994 regulated emission target the cost burden

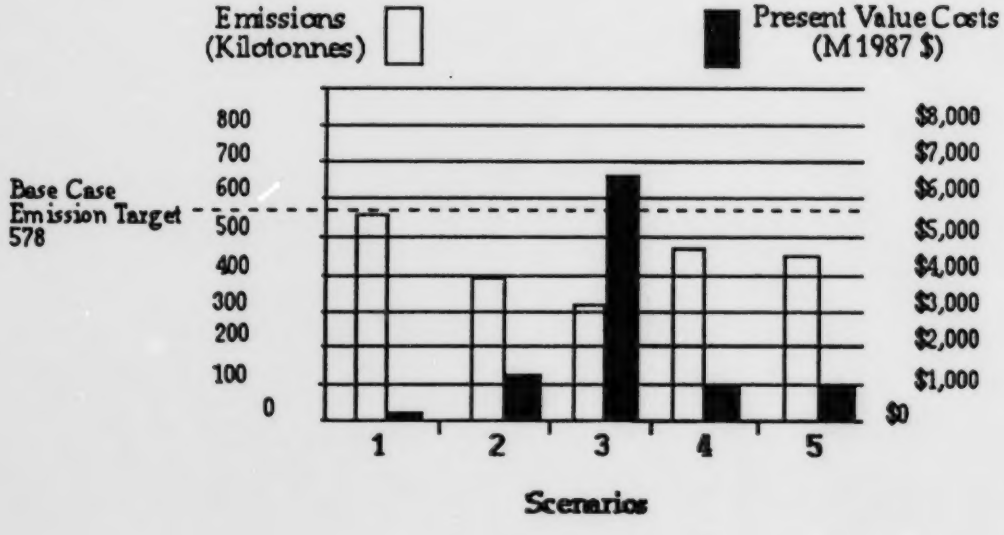
1incurred by other sectors to achieve the 1994 emission target is considerably reduced relative to Scenario 4.

A failure by Ontario Hydro to meet its 1994 targets has implications which are less severe although still costly. If Ontario Hydro fails to reduce its emissions and remains at 1985 emission levels (Scenario 6), the 1994 targets can be achieved by other sectors at a cost of $321 million . If Ontario Hydro achieves half of its 1994 regulated reductions (Scenario 7), other sectors incur a cost of $78 million.

the implications of "what if for NO_x"

Similar to SO_2, a series of "what if scenarios" were formulated and tested for NO_x to determine the most cost-effective across the board strategy for abatement. Scenarios 1,2 and 3 examined the impact of lowering an existing base case emissions/target of 578,135 tonnes per year by margins of 10, 30 and 50 per cent . Another two scenarios, 4 and 5 respectively examined what would happen if Ontario Hydro failed to reduce emissions below the 1985 levels and if it only reduced emissions by 50 per cent of the 1994 regulated target. Figure 8 shows the annual emissions and the costs that would be incurred for each scenario.

Figure 8
Projected NO_x Emission Levels and Associated Costs
(Source: Appendix 3, Table 4.6-4.8)



For the first three scenarios the results show that the costs of removal escalate dramatically as emission targets become lower. The 30 per cent NOx removal specified in Scenario 2 costs 5.5 times as much as the 10% cut specified in Scenario 1. Scenario 3 costs 30 times as much as Scenario 1 for a 50 per cent level of NO_X removal.

The scenarios which look at total and partial failure of Ontario Hydro to meet its 1994 regulated emission targets reveal that the effects are readily offset by federally mandated mobile source controls which are now in effect for new vehicles.

conclusions

A failure on the part of either INCO or Ontario Hydro to achieve regulated SO_2 emission levels has significant implications for province wide emission control costs. If INCO emissions remain at 1985 levels, the $4,933 million expenditure by other sectors will leave the province at an emission level of 1.01 million tonnes per year or 13 per cent above the 1994 target. Failure by Ontario Hydro to reduce emissions below 1985 levels would cost other sectors $321 million but the 1994 targets would be met.

In the case of NO_X, mobile emission control is the critical factor. Should Ontario Hydro, the major point source of NO_X not reduce emissions below 1985 levels mobile reductions would more than compensate for the shortfall.

Provided INCO and Ontario Hydro meet their 1994 targets, the Province can turn to regulating further reductions across the board or by specific point source and industry sector. Based on the Scenarios that were run for both SO_2 and NO_X a 10 per cent reduction incurs a relatively low cost. A reduction of 30 per cent increases costs five and a half times over those for the ten per cent reduction. Further control measures which would reduce emissions from the sectors to 50 per cent of the 1994 tar get levels would increase the costs to about 30 times those for the 10 per cent reduction.

Based on the progress made by the regulated companies in the past three years, we expect that the four major point sources in Ontario will be able to meet their 1994 SO_2 and NO_X emission targets.

Switching from other fuels to natural gas may reduce fuel costs and reduce SO_2 and NO_X emissions. However, supply limitations due to pipeline capacity constraints preclude the widespread application of this abatement method.

Conservation was not examined.

Other assumptions not covered in this study can be easily added to the model to provide the policy-maker with new scenarios based on technological advances, changes in costs, or calculations based on social costs instead of private costs. The model itself has been revised to run on a P.C.

future issues

1. Investigate implications of switching fuel sources to natural gas.

2. Consider implications of more stringent emission limits on mobile sources, eg. transportation vehicles.

3. The incremental costs of further SO_2 reductions at the four major point sources should be examined in detail.

4. Explore implications of significant modal changes (eg. from automobile to public transit) on NO_x emissions.

COUNTDOWN ACID RAIN
FUTURE ABATEMENT STRATEGIES
Phase I

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This Document	**This document describes Phase I, Appendix 1.**

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EXECUTIVE SUMMARY - PHASE I

This report is Phase I (Emission Inventory Updates) of the project entitled "Countdown Acid Rain Future Abatement Strategies". The information from Phase I will be used in Phase II (Alternative Technologies) and Phase III (Abatement Strategy Assessment). The overall objective of the study was to evaluate the cost effectiveness of alternative emission control technologies for SO_2 and NO_x emissions.

The objective of Phase I was to develop an appropriate emission inventory of sulphur dioxide (SO_2) and nitrogen oxides (NO_x). The report presents summarized SO_2 and NO_x emission data for the major point sources of SO_2 and NO_x, for industrial sectors and area sources in Ontario for 1985, which is the new reference year for acid rain studies. "Area sources" include transportation and fuel combustion.

Sulphur dioxide emissions decreased from 1980 to 1985. The total anthropogenic (man-made) SO_2 emissions in 1985 amounted to 1.458 million tonnes; a decrease of 16.6% from the 1980 emission levels. The Inco smelter was the largest contributor to the reduction. The largest emission sources in 1985 were non-ferrous smelters, 53%, electric utilities, 23% and ferrous smelters, 10%. Area sources accounted for approximately 4% of the total SO_2 emissions; within this group, marine and residential heating dropped by over half, while vehicle emissions increased by 15%.

Nitrogen oxide emissions increased from 1980 to 1985. Approximately 0.612 million tonnes of anthropogenic NO_x were emitted in 1985, an approximate increase of 6% from the 1980 emission levels. The largest contributors were vehicles, 53% and electric utilities, 15%. Vehicle emissions increased by 17.6%. Ontario Hydro dominates the industrial sector, and its emissions fluctuated during 1980-1985. Low NO_x burners have helped to reduce emissions. Legislated limits under the Count Down Acid Rain Programme are forcing emission reductions for the four major point sources. The schedules are shown. Five scenarios were developed with assumptions about future emissions, and will be employed in Phase II and Phase III to assess the effect of various strategies on the cost and employment of abatement methods and technologies.

1.0 INTRODUCTION

This report is Phase I (Emission Inventory Updates) of the project entitled "Countdown Acid Rain Future Abatement Strategies". The objective of Phase I is to develop an appropriate emission source inventory for sulphur dioxide (SO_2) and nitrogen oxides (NO_x). The inventory incorporates data from the 1985 Ontario Emission Inventory System (OEIS), a computerized data management system and a previous MOE study, MOE 1986a.

The overall objective of the report is to use data from previously inventoried sources to evaluate various abatement scenarios in terms of the reduction in SO_2 and NO_x emissions versus cost.

The report summarizes:

- the SO_2 and NO_x emissions for the major point sources, industrial sectors and area sources in Ontario for 1985,
- the trend in SO_2 and NO_x emissions during the period 1980 to 1985,
- the status quo inventory based on industries achieving regulated limits,
- and several emission inventories based on a large source not being able to meet legislative control, a major economic upturn, a major change in industrial feedstock, and a significant new emission source.

The data presented in this report refer to emissions from anthropogenic (man-made) origins. The emissions of nitrogen oxides (NO_x) are calculated as nitrogen dioxide in the inventory and in this report. It should be noted that the regulation applying to Ontario Hydro refers to nitric oxide (NO).

2.0 SO_2 EMISSIONS

2.1 SO_2 Emissions in 1985

The total 1985 SO_2 emissions in Ontario were approximately 1,458 kilotonnes. Figure 1 presents the breakdown of SO_2 emissions in terms of industrial sectors and area sources. Non-ferrous smelters accounted for the largest source of emissions (53%), followed by electric utilities (23%), and ferrous smelters, 10%.

In the following sections, point sources are defined as industrial facilities, electric utilities and institutions. Area sources include transportation equipment (vehicles, railroad, aircraft and marine), heating (residential, commercial, industrial and institutional) and incineration.

Point Sources

Table 1 presents the 15 largest point sources of SO_2 emissions in 1985; the selection criteria was >5000 tonnes/year SO_2. These sources account for 90.3% of the provincial total. The largest emitter was INCO with an annual emission rate of 695 kilotonnes. Ontario Hydro, i.e. cumulative sum from thermal generating stations, was second with an annual emission rate of 336.6 kilotonnes.

The top four point sources on Table 1 accounted for 84% of the total provincial emissions. Facility specific legislative control, described in Chapter 4.0, has been placed on each of these sources.

Area Sources

Figure 2 presents the 1985 SO_2 emissions from area sources which account for 3.8% of the provincial total. The largest area source of SO_2 emissions was vehicles, 32.8%, and industrial/commercial heating, 25.6%.

FIGURE 1

SO_2 PROVINCIAL TOTALS (1985)

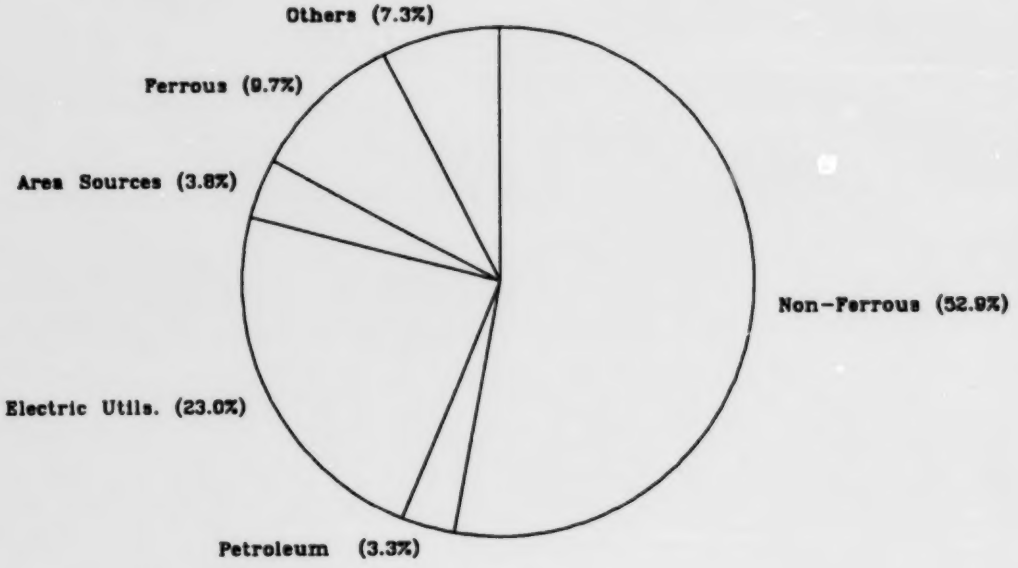
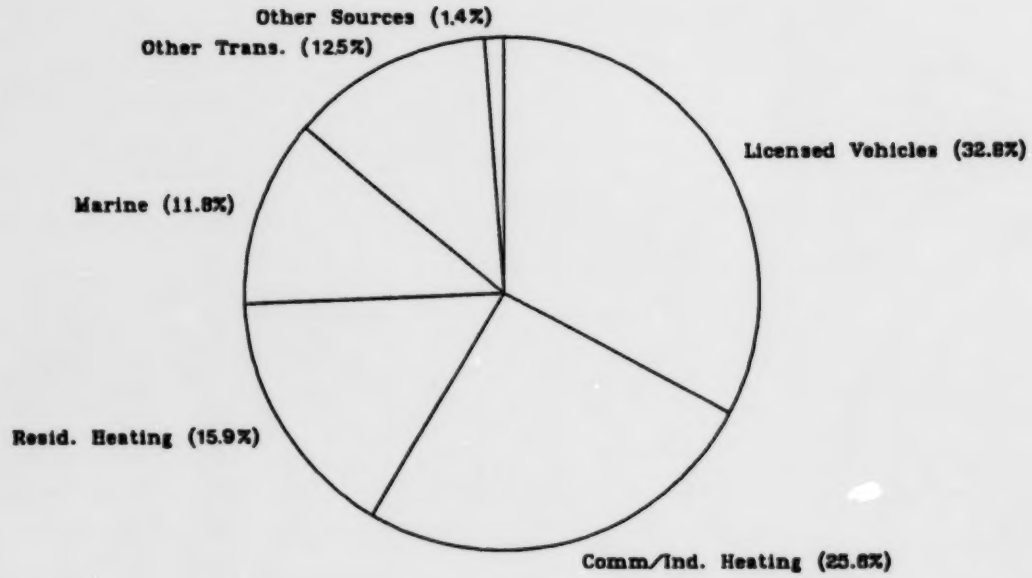


FIGURE 2

SO_2 AREA EMISSIONS (1985)



NOTE:

FIGURE 2 IS A BREAKDOWN OF 3.8 % SO_2 AREA SOURCES FROM FIGURE 1

Table 1

15 MAJOR POINT SOURCES OF SO_2 IN ONTARIO* (1985)

Source	SO_2 (tonnes/year)
1. INCO (Sudbury)	695,008
2. Ontario Hydro**	336,633
3. Algoma Ore Div. (Wawa)	115,890
4. Falconbridge Nickel Mines (Sudbury)	74,352
5. Imperial Oil (Sarnia)	19,595
6. Shell Canada (Corunna)	16,103
7. Lake Ontario Cement (Picton)	7,748
8. Algoma Steel Corp. (Sault Ste. Marie)	7,419
9. Stelco (Nanticoke)	6,920
10. Courtauld's Can. Ltd. (Cornwall)	6,517
11. Petrosar Ltd. (Corunna)	6,260
12. James River Marathon (Marathon)	6,225
13. Texaco Canada (Nanticoke)	6,210
14. Dofasco Inc. (Hamilton)	6,126
15. Kerr Addison (Virgniatown)	5,144
	1,316,150

90.3% of total SO_2 emissions from area and point sources

Note:

* Criteria >5000 tonnes/year SO_2

** Ontario Hydro includes:

Nanticoke	169,000
Lambton	118,000
Lakeview	43,800
Thunder Bay	4,740
Atikokan	1,040

Reference:

MOE, 1988.

2.2 SO_2 Trends from 1980 to 1985

Point Sources

Table 2 presents the SO_2 emissions from industrial point sources for the period 1980 to 1985. Non-ferrous and ferrous smelters, i.e. iron ore (Wawa) and iron & steel, show depressed emissions during 1982/1983; a period of economic recession. Electric utilities, however, showed an inverse relationship to the aforementioned trend, i.e. peak production during 1982 and 1983. In 1982, electric utilities were the major source of SO_2 emissions. The decrease in SO_2 emissions during the period of 1983 to 1985 may be at least partially attributable to the Pickering "B" nuclear generating station coming on line.

Emissions from petroleum refineries have steadily decreased since 1980. This may be due primarily to a reduction in the sulphur content of feed stock and some conversion to natural gas as a fuel at some refineries.

The total annual emissions of SO_2 from point sources during the review period (1980-85) are presented on Figure 3. During the period of 1980 to 1982, emission levels dropped significantly, approximately 36% compared to 1980. Overall, a 17% reduction occurred between the period 1980 and 1985; the most significant source of reduction is in emissions from non-ferrous smelters, in particular INCO.

The 1984 data for SO_2 emissions are presently unavailable. The MOE is currently processing this data, the 1985 data was processed before the 1984 data because it is the base year for the Countdown on Acid Rain study.

Area Sources

The Ontario area source emissions of SO_2 from 1980 to 1985 are presented in Table 3. Significant decreases have occurred, in marine, 57%, and residential heating, 56% during this period. Total vehicle emissions have increased 15% since 1980.

Table 2

ONTARIO SO_2 EMISSIONS FROM INDUSTRIAL SOURCES FROM 1980 TO 1985*

(TONNES/YEAR)

Category	1980(1)	1981(1)	1982(1)	1983(1)	1985(2)**
Non-Ferrous Smelters	935,451	836,172	388,773	538,007	769,360
Electric Utilities	396,194	417,658	450,368	437,630	336,738
Iron Ore (Wawa)	160,583	132,337	70,690	81,827	115,890
Petroleum Refineries	73,627	72,348	64,785	59,465	59,698
Iron & Steel	29,909	25,143	21,910	21,760	26,028
Other Sources	90,887	91,611	90,508	84,643	95,056
TOTAL	1,686,651	1,575,269	1,087,034	1,223,332	1,402,770

Note:

1984 data is presently unavailable.

1985 is the base year for planning future acid rain controls in Canada and U.S.A.

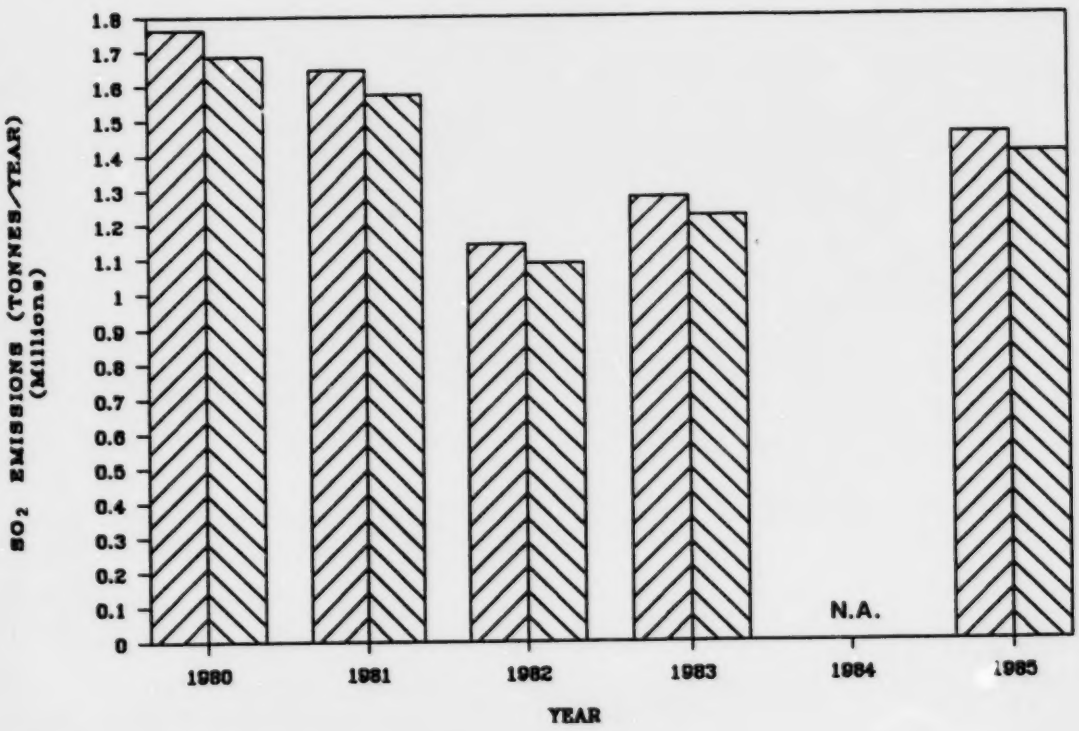
Reference:

(1) MOE, 1986a.

(2) MOE, 1988; OEIS System.

FIGURE 3

TOTAL SO_2 EMISSIONS (1980 - 1985)



LEGEND:

TOTAL

POINT SOURCE

Table 3

ONTARIO SO_2 AREA EMISSIONS FROM 1980 TO 1985*

(TONNES/YEAR)

Category	1980(1)	1981(1)	1982(1)	1983(1)	1985(2)**
License Vehicles	15,808	15,102	15,576	15,256	18,174
Off-Hwy. Engines	3,517	3,592	3,055	3,154	3,335
Railroad	4,564	4,809	4,525	4,580	3,448
Aircraft	173	173	165	163	188
Marine	15,360	12,299	8,714	11,429	6,530
Residential Heating	20,272	15,294	13,604	8,574	8,825
Comm./Inst./Indust. Heating	16,910	18,870	10,704	10,880	14,183
Waste Incineration	646	642	611	609	671
TOTAL	77,250	70,781	56,954	54,645	55,354

Note:

* 1984 data is presently unavailable.

** 1985 is the base year for planning future acid rain controls in Canada and U.S.A.

Reference:

(1) MOE, 1986a.

(2) MOE, 1988; OEIS System.

The total Ontario emissions of SO_2 from area sources have decreased from 77.3 kilotonnes to 55.3 kilotonnes, a reduction of 28%.

3.0 NO_X EMISSIONS

3.1 NO_x Emissions in 1985

The total 1985 NO_x anthropogenic emissions for Ontario were approximately 612 kilotonnes. Figure 4 presents a breakdown of NO_x emissions in terms of industrial sectors and area sources. In 1985, the largest contribution to NO_x emissions was area sources, 71.1%, with electric utilities contributing 15.4%.

Point Sources

Table 4 presents the ten highest point sources of emission of NO_x in Ontario. These sources account for 21% of the provincial total.

The largest source of industrial emissions of NO_x was Ontario Hydro with a cumulative total from its thermal generating plants of 94,437 tonnes.

Area Sources

Figure 5 presents the 1985 NO_x emissions from area sources. The largest area sources were licensed vehicles, 75.1%. Other forms of transportation accounted for 16.1%.

3.2 NO_x Trends from 1980 to 1985

Point Sources

Table 5 presents the Ontario NO_x emissions from industrial sources for the period 1980-1985. Since 1985 is the basis for planning future acid rain controls in Canada, the 1985 inventory has been finalized; the 1984 inventory will be finalized later. The sector with the greatest change was petroleum refineries which decreased NO_x emissions from 23,214 tonnes to 17,730 tonnes during the period of 1980 to 1985, a 24% reduction, a reduction which may be

FIGURE 4

NO_x PROVINCIAL TOTALS (1985)

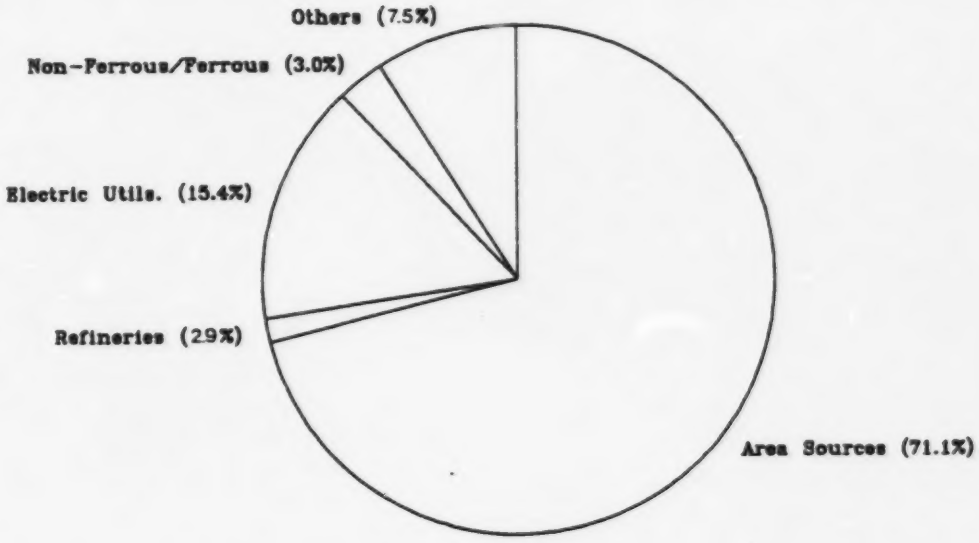
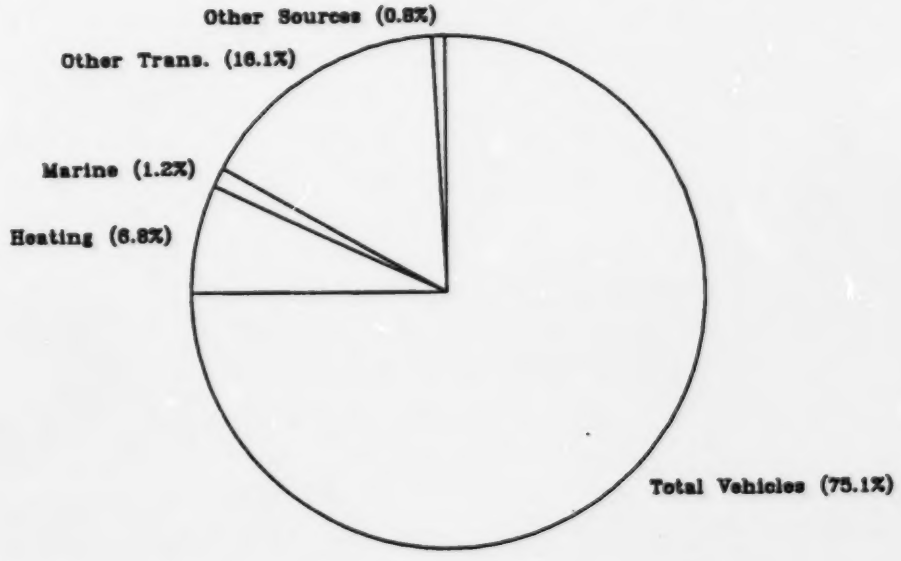


FIGURE 5

NO_x AREA EMISSIONS (1985)



NOTE:

FIGURE 5 IS A BREAKDOWN OF 71.1 % NO_x AREA SOURCES FROM FIGURE 4

Table 4

10 MAJOR POINT SOURCES OF NO_x IN ONTARIO* (1985)

Source	NO_x (tonnes/year)
1. Ontario Hydro**	94,437
2. Stelco (Hamilton)	5,567
3. Petrosar Ltd. (Corunna)	5,525
4. INCO (Sudbury)	4,893
5. Imperial Oil (Sarnia)	3,629
6. Algoma Steel Division (Sault Ste. Marie)	3,207
7. Dow Chemical (Sarnia)	3,080
8. ESSO Chemicals (Sarnia)	2,920
9. Stelco (Nanticoke)	2,602
10. Gulf Canada Ltd. (Mississauga)	2,238
	128,098

21% of total NO_x emissions from point and area sources

Note:

* criteria >2000 tonnes/year NO_x

** Ontario Hydro Includes:

Nanticoke	59,799
Lambton	18,400
Lakeview	13,646
Thunder Bay	2,147
Atikokan	445

Reference:

MOE, 1988, OEIS System.

Table 5

ONTARIO NO_x EMISSIONS FROM INDUSTRIAL SOURCES FROM 1980 TO 1985*

(TONNES/YEAR)

Category	1980(1)	1981(1)	1982(1)	1983(1)	1985(2)**
Electric Utilities	100,976	108,992	123,549	118,426	94,437
Petroleum Refineries	23,214	19,380	19,315	17,449	17,730
Iron & Steel	12,118	15,705	15,705	11,309	13,676
Non-Ferrous Smelters	2,530	2,930	2,930	2,930	4,914
Other Sources	36,192	39,131	38,786	35,202	45,929
TOTAL	175,030	186,138	200,285	185,316	176,686

Note:

* 1984 data is presently unavailable.

** 1985 is the base year for planning future acid rain controls in Canada and U.S.A.

Reference:

(1) MOE, 1986a.

(2) MOE, 1988; OEIS System.

attributed to the conversion to natural gas as a fuel source within some refineries.

As was the case with SO_2 emissions, the NO_x emissions from electric utilities were highest during 1982 and 1983. The installation of low NO_x burners at Nanticoke generating station and Pickering "B" nuclear generating station coming on line in 1985 accounts for some of the NO_x reduction.

The total NO_x emission levels from industrial sources increased slightly in 1985, (176,686 tonnes) from the 1980 level (175,030 tonnes), i.e. an increase of 1%.

Area Sources

Table 6 presents the Ontario area source emissions of NO_x from 1980 to 1985. The NO_x emissions from licensed vehicles has increased significantly, a 17.6% increase, from 277,836 tonnes in 1983 to 326,603 tonnes in 1985.

The overall area NO_x emissions in 1985 has increased by 2.4% over the 1980 value. If fires are excluded, however, a much larger increase in NO_x emissions, 8.7%, occurred for the same period.

Table 6

ONTARIO NO_x AREA EMISSIONS FROM 1980 to 1985* (TONNES/YEAR)

Category	1980 (1)	1981 (1)	1982 (1)	1983 (1)	1985 (2)**
Anthropogenic:					
Licensed Vehicles	277,836	265,866	279,421	272,495	326,603
Off-Hwy. Engines	49,191	50,584	42,360	43,847	46,140
Railroad	29,533	31,117	29,282	29,633	22,308
Aircraft	1,679	1,681	1,592	1,576	1,828
Marine	8,449	7,039	5,825	7,701	5,435
Residential Heating	18,626	17,237	16,837	14,711	15,556
Commercial Heating	10,007	11,772	10,549	10,210	9,629
Industrial Heating	2,187	2,005	1,145	2,356	4,574
Waste Incineration	2,662	2,643	2,593	2,580	2,743
Sub Total	400,170	389,944	389,604	385,109	434,816
Non-anthropogenic:					
Forest & Structural Fires	25,151	8,396	707	20,073	508
TOTAL	425,321	398,340	390,311	405,182	435,324

Note:

* 1984 data is presently unavailable.

** 1985 is the base year for planning future acid rain controls in Canada and U.S.A.

Reference:

(1) MOE, 1986a.

(2) MOE, 1988; OEIS System.

4.0 SO_2 AND NO_x REGULATIONS

Table 7 presents the four major sources, their 1985 emission rates and the 1994 emission limits. In order to achieve the 1994 emission limits, INCO and Ontario Hydro must reduce their emissions from 1985 rates by 61.9% (SO_2) and 50% (SO_2 and NO_x), respectively. Because 1985 emission levels for Algoma Steel Corp (Wawa) and Falconbridge were below their 1994 SO_2 emission limits, further reductions would not be required for these sources.

In order for INCO to achieve the legislative control, the annual emission rate from its Sudbury operations must be reduced 61.9% from the 1985 rate to 265 kilotonnes SO_2.

Ontario Hydro, however, has several thermal generating stations which emit SO_2 and NO_x. The criteria employed by Ontario Hydro for the selection of preferred candidate sites for installing Flue Gas Desulphurization (FGD) equipment includes (Ontario Hydro, 1988):

- sulphur content of coal that the station is designed to burn;
- expected future use of the station; and
- station size, remaining operating life, and expected reliability

The number of FGD units required to achieve the 1994 emission limit will be discussed in Phase II (Alternative Technologies) and Phase III (Abatement Strategy Assessment). For Phase I, it has been assumed that Ontario Hydro will meet the Regulation by emitting 175 kilotonnes SO_2 and 40 kilotonnes NO (61.3 kilotonnes NO_x).

Table 7

LEGISLATIVE (1994) CONTROL
ANNUAL SO_2 AND NO_x EMISSIONS (KILOTONNES)

Company	Regulation	Current (1985) SO_2	Current (1985) NO_x	Emission (1994) Limits SO_2	Emission (1994) Limits SO_2 + NO_x
INCO	660/85	695.0	4.9	265	-
Ontario Hydro	281/87	336.6	94.4	175	215
Algoma (Wawa)	663/85	115.9	0.3*	125	-
Falconbridge	661/85	74.4	<0.5*	100	-

* Estimated

Reference:

MOE, 1986b.

5.0 BASIC EMISSION SCENARIOS

5.1 Introduction

Five basic emission scenarios were developed for the Phase I study:

1 - Status Quo
2 - Major Economic Upturn
3 - Major Change in Industrial Feedstock
4 - Significant New Emission Sources
5 - Large Source Not Meeting Legislative Control

These scenarios will be employed during Phases II and III to assess the effect of various abatement strategies.

In Phases II and III, the first four inventories will be evaluated under the following two scenarios:

- All industries reducing SO_2 and NO_x emissions by 10%, 30% and 50%.
- The emissions of the four largest SO_2 sources meeting current regulatory constraints while other industries reduce SO_2 and NO_x emissions by 10%, 30% and 50%.

The last scenario, scenario 5, will be evaluated by assuming that INCO will reduce SO_2 emissions to 525,000 tonnes per year and maintain NO_x emissions at 4900 tonnes per year. The SO_x and NO_x emissions from all other industries will be reduced to achieve overall reductions of 10%, 30% and 50%.

5.2 Status Quo Scenario

Two potential options exist for the status quo scenario. Under the first option, Ontario Hydro would comply with the regulation by reducing SO_2 emissions to 175,000 tonnes per year and NO_x emissions to 40,000 tonnes NO per

year. Regulation 281/87 also suggests a second new NO_x scenario where Ontario Hydro would probably double its NO_x emissions to 80,000 tonnes NO per year, but complies with the regulation by reducing SO_2 emissions by additional scrubbing of 40,000 tonnes per year.

The status quo scenario utilizes emission data for the four largest SO_2 emission sources, 11 industrial sectors and four area sources (see Table 8). The emission rates for the four largest sources are those required by the specific regulations, (see Chapter 4.0). The industrial sectors are as defined by Statistics Canada (1983,1984, and 1985)

The first two area sources represent major transportation regions in Ontario. The marine sources were isolated because fuel used for lake freighters is not covered by provincial jurisdiction.

The total SO_2 emissions in the status quo scenario exceeds the Provincial objective, 885,000 tonnes/yr after 1993, by 15,862 tonnes/yr. In the status quo scenario, it is implicitly assumed that Algoma Steel Corp. (Wawa) and Falconbridge Nickel Mines will increase emissions from the 1985 level to their maximum acceptable levels as stated in the regulations, (see Section 4.0) even though this may not occur.

In option 2, Ontario Hydro would emit 80 kilotonnes of NO and 135 kilotonnes of SO_2 per year. Table 9 presents the status quo scenario for option 2.

5.3 Major Economic Upturn

Table 10 presents an estimate of growth in the various industrial sectors, derived from the forecast Manufacturing Gross Domestic Product at Factor Cost data for the period 1994 to 2000 in Ontario (Informetrica, 1987). It has been assumed that industrial emissions of SO_2 and NO_x will increase linearly with these growth terms to evaluate the effect of a major economic upturn in the economy.

Table 8

STATUS QUO SCENARIO - OPTION 1

Source	SO_2 (tonnes/year)	NO_x (tonnes/year)
INCO	265,000	4,900
Ontario Hydro	175,000	61,333
Algoma Ore Division (Wawa)	125,000	260
Falconbridge Nickel Mines	100,000	20
Industrial Sectors:		
Food/Beverage/Tobacco	1,647	2,881
Rubber Plastics	185	386
Leather/Textile/Clothing	7,359	1,254
Paper Products & Allied Industries.	30,621	12,179
Primary Metals	14,219	672
Metal Fabricating/Machinery Industries	29,038	14,662
Transportation Equipment Industries	1,801	2,099
Non-Metallic Mineral Products	20,249	9,756
Chemical & Petroleum Products	69,902	27,892
Misc. Manufacturing	192	267
Other Major Groups	5,318	4,250
Industry Sub Total	845,531	142,811
Area Sources:		
Metro Toronto area	18,603	101,812
Niagara-Hamilton-Toronto Corridor	24,154	202,954
Balance of Ontario	6,067	125,124
Marine Sources	6,530	5,434
Area Source Sub Total	55,354	435,324
TOTAL	900,885*	578,135

Reference:
MOE, 1988; OEIS System

* Ontario will meet SO_2 emission limits of 885,000 tonnes/year in 1994. The higher value, 900,885 tonnes/year arises from the implicit assumption that Algoma Steel Corp. (Wawa) and Falconbridge Nickel Mines will increase emissions to their maximum acceptable levels.

Table 9

STATUS QUO SCENARIO - OPTION 2

Source	SO_2 (tonnes/year)	NO_x (tonnes/year)
INCO	265,000	4,900
Ontario Hydro	135,000	122,666
Algoma Ore Division (Wawa)	125,000	260
Falconbridge Nickel Mines	100,000	20
Industrial Sectors:		
Food/Beverage/Tobacco	1,647	2,881
Rubber Plastics	185	386
Leather/Textile/Clothing	7,359	1,254
Paper Products & Allied Industries.	30,621	12,179
Primary Metals	14,219	672
Metal Fabricating/Machinery Industries	29,038	14,662
Transportation Equipment Industries	1,801	2,099
Non-Metallic Mineral Products	20,249	9,756
Chemical & Petroleum Products	69,902	27,892
Misc. Manufacturing	192	267
Other Major Groups	5,318	4,250
Industry Sub Total	805,531	204,144
Area Sources:		
Metro Toronto area	18,603	101,812
Niagara-Hamilton-Toronto Corridor	24,154	202,954
Balance of Ontario	6,067	125,124
Marine Sources	6,530	5,434
Area Source Sub Total	55,354	435,324
TOTAL	860,885	639,468

Reference:

MOE, 1988; OEIS System

Table 10

ANNUAL GROWTH RATE

Industrial Sector	Average Annual Growth Rate (%)
Food/Beverage	2.4
Rubber & Plastics	3.5
Leather/Textile/Clothing	2.6
Paper and Allied Industries	3.0
Primary Metals	3.6
Metal Fabricating/Machinery Industries	6.1
Transportation Equipment (manufacturing)	3.4
Non-Metallic Mineral Products	4.2
Chemical & Petroleum Products	3.0
Misc. Manufacturing	3.7

Note:

Based on Forecasted Growth from 1994 to 2000.

Reference:

Informetrica Limited, 1987

Production data for Ontario in 1982, 1983 and 1984, a period of high growth following the 1982 recession, was also examined but yielded very high and perhaps unrepresentative growth rates in some industrial sectors, i.e. primary metals (Statistics Canada, 1983, 1984 and 1985).

5.4 Major Change in Industrial Feedstock

The desulphurization of petroleum products was assumed as the major change in industrial feedstock. Changes which would only affect the top four SO_2 emitters, e.g. the use of low sulphur coal from western Canada by Ontario Hydro, will not be examined as specific methods by which these companies choose to meet legislative control are not critical to this study.

5.5 Significant New Emissions Source

In this scenario, the effect of a significant new emission source or sources will be assessed. All of the new sources with significant SO_2/NO_x emissions will be assumed to have Best Available Control Technology (BACT). The source(s) will be treated separately from the existing inventory and with BACT, are assumed to emit no more than 5% of the overall industrial SO_2 (42,276 tonnes) and NO_x (8796 tonnes) emissions shown in the Status Quo Inventory, Option 1.

5.6 Large Source Not Meeting Legislative Control

In order to assess the impact on total emissions if a currently legislated source can not meet legislative control, it will be assumed for the purposes of this study that INCO will not be able to meet the 1994 legislative control, but is able to reach a level of 525 kilotonnes SO_2 per year.

The aforementioned assumptions are for the purpose of assessing large changes in SO_2 emissions and are not meant to reflect the current status of INCO's or any other abatement program.

REFERENCE

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COUNTDOWN ACID RAIN

FUTURE ABATEMENT STRATEGIES

PHASE II

For the

Ministry of the Environment

Air Resources Branch

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DISCLAIMER

The conclusions, opinions and recommendations expressed in this report are those of the consultant and do not necessarily represent the views of the Ontario Ministry of the Environment. In addition, the consultant is solely responsible for the accuracy of data and estimates presented in this report.

FOREWORD

This report presents a study of SO_2 and NO_x emission sources in Ontario and proposed emission control strategies to achieve further reductions of SO_2 and NO_x after 1993. The report consists of a summary document supported by three appendices.

Summary — The summary document describes the findings of 3 phases of the study and draws conclusions on abatement strategies.

Appendix 1 — The Phase 1 Report sets out a 1985 base year emission inventory for SO_2 and NO_x, examines past trends, and outlines five basic future scenarios.

Appendix 2 — The Phase II Report identifies the costs of reducing SO_2 and NO_x using alternative emission control technologies required to meet the emission targets identified in the Phase I Report.

Appendix 3 — The Phase III Report develops alternative cost-effective abatement strategies that achieve pre-specified aggregate emission targets. The computer model developed for the foregoing work is described.

This Document — **This document describes Phase II, Appendix 2.**

1 The numerical information contained in the Tables of this Phase II document differ slightly from the data in Tables 8 and 9 (Scenario 1 and 2) of the Phase I document. When detailed cost estimates were being made it was found that some entries in the emission inventory were assigned to incorrect S.I.C. codes. They were reallocated for costing purposes and the total emissions for each sector were correspondingly adjusted for this report.

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EXECUTIVE SUMMARY - PHASE II

This report is Phase II (Alternative Technology Inventory and Costs) of the project entitled "Countdown Acid Rain Future Abatement Strategies". The information collected in Phase II will be used in Phase III (Abatement Strategy Assessment) to evaluate the cost/effectiveness of selected alternative emission control technologies for SO_2 and NO_x emissions.

The objective of Phase II is to identify and determine the costs and contaminant removal capability of alternative emission control technologies. The gross cost data presented includes capital, operating, and annualized costs. The costs are approximate estimates which can vary by a factor of two or more depending on the specific design needs, installation costs and operating mode.

The emissions from industrial sectors and large point sources are subdivided into process and boiler emissions. For the large point sources, the alternative abatement technologies presented are specific for the process emissions. With the exception of Ontario Hydro, the technologies for the boilers are generic. Alternative abatement strategies for the industrial sectors are generic.

Costs for the control technologies applied to each sector have been estimated by calculating costs for a representative unit and multiplying that cost by the number of sources which might be controlled by the technology used. The programmes used to develop costs were based on algorithms and procedures which have been verified by use in other studies.

The costs for SO_2 removal vary over such a wide range that the application of some technologies would not be practical. The high costs in certain situations point out the site-specific nature of the problem. Costs were found to range from $110 to $99,873 per tonne of SO_2 removed. At the other extremem, an apparent saving would result from the replacement of sulphur bearing fuels with natural gas, although practical and marketing problems

prevent a wide spread application of the approach. In general the least costly strategies result from control of high SO_2 content from high volume sources.

Costs for the control of NO_x were found to vary between a savings of $20,985 and a cost of $21,551 per tonne removed. The least costly methods are those which require combustion process changes and result in low removal efficiencies.

1.0 INTRODUCTION

1.1 Overall Objective

This report presents the results of Phase II work in the project entitled "Countdown Acid Rain Future Abatement Strategies". It identifies the gross costs and performance effectiveness of alternative emission control technologies for post 1994 SO_2 and NO_x abatement in Ontario.

Although transportation is a key source of NO_x emissions in the Province, it is not dealt with in this document. A separate report that looks at abatement technologies and costs associated with emission reduction in this sector is being prepared independently. When complete, the results of the transportation study and this document will be combined in Phase III to present an aggregate picture of abatement strategies for SO_2 and NO_x in Ontario.

Three chapters follow. They respectively present:

2.0 . alternative emission control technologies for SO_2 and NO_x emissions from large point sources and industrial sectors

3.0 . descriptions of the costing procedures used for sources of NO_x and SO_2 emissions

4.0 . estimates of the operating and capital costs associated with alternative emission control technologies

The analyses contained in this document are founded on three assumptions. These are:

1) Ontario Hydro will achieve its 1994 emission limits, and potentially additional reductions of SO_2 and NO_x by adding flue gas desulphurization (FGD) and selective catalytic reduction (SCR) abatement equipment to its fossil fuel fired generation facilities.

2) INCO, Falconbridge and Algoma will achieve their 1994 SO_2 emission limits by employing process changes and abatement technology, but will need to employ different technology to achieve additional reductions of SO_2 after 1994.

3) Individual industrial sectors will achieve reductions in SO_2 and NO_x emissions as a result of an increasing number of companies utilizing the selected abatement equipment.

2.0 ALTERNATIVE EMISSION CONTROL TECHNOLOGY

2.1 Introduction

This chapter sets out alternative control technologies for SO_2 and NO_x abatement in a generic form for broad-industrial sectors and in a specific context for the four largest SO_2 emission sources namely INCO, Ontario Hydro, Falconbridge and Algoma.

The control technologies which have been examined by the four largest SO_2 emitters will enable them to comply with 1994 targets prescribed in government regulations.

Alternative emission control technologies presented in this chapter and throughout the remainder of the text refer to both process changes and the installation of control equipment.

Tables 2-1 (A and B) present an inventory of SO_2 and NO_x emission control technologies and respectively indicate which are applicable to industry in general and each of the four largest emitters. (The text which follows provides a general description of these technologies.)

2.2 Industrial Sectors

The Phase I inventory data base contained eighteen sectors giving rise to SO_2 and NO_x emissions. The emissions from eight of these sectors amount to less than 1% of the total No_x and SO_2 emissions and were excluded from the study. In addition, the Rubber and Plastics Industry sector was included only with respect to SO_2 emissions. The sectors of concern are:

Included	Excluded
Primary Metals	Tobacco Industries
Transportation Equipment	Leather Industries

Table 2.1A

AVAILABLE ABATEMENT CONTROLS - SO_2

	General Industry Sectors	Falcon-bridge	INCO	Algoma	Ontario Hydro	Refin-eries	COMMENTS
SO_2 CONTROL							
Pre-Combustion Controls							
Coal Cleaning	x				x		Not relevant in Ontario, equivalent in cost to lower S content fuel.
Ore beneficiation		ø	ø	x			Used at INCO and Falconbridge, could be used at Algoma.
Fuel switching	x				x	x	Oil switching equivalent to ref'n'y desulfurization, use of Nat. Gas universally is not practicable.
Petroleum fuel desulfurization	x				x	x	Applied at refinery, equivalent to fuel switching.
Process Changes							
Raw material changes	x					x	Not assessed in this study
Operating changes	x	x	x	x		x	Only assessed for refineries, (oil desulfurization).
Equipment changes	x	x	x			x	Being undertaken by nonferrous industry. Fluid bed combustion for solid waste incineration.
Combustion controls							
Fuel Additives	x				x		Negligible effect unless large amounts of expensive additives are used.
Dry lime addition to fuel	x			x	x		Of use on coal boilers and incinerators of solid fuel. Low and variable efficiency.
Lime injection modified burners.	x				x		Used for pulverized coal burners. Efficiency depends on lime particle size.
Emission Controls.							
Wet FGD Systems							
- Lime/limestone scrubbing	x	x	x	x	x	x	Throwaway processes - can oxidize to Gypsum commonly used on electric power stations kiln used to free SO2 leaving MgO.

TABLE 2.1A, continued

	General Industry Sectors	Falcon-bridge	INCO	Algoma	Ontario Hydro	Refin-eries	COMMENTS
- Dual Alkali	x	x	x	x	x	x	Absorbs in NaOH - recovers NaOH - calcium salts produced - throwaway.
- Sodium carbonate scrubbing	x	x	x	x	x	x	Soluble product - throwaway - costly sodium salts needed by process.
- Magox process	xx	x	x	x	x	x	Recovers SO2 - Magnesium reagent costly
- Wellman-Lord process	x	x	x	x	x	x	Recovers Sulphuric acid, SO3 or SO2. SO2 can be converted to free Sulfur.
- Cominco process	x	x	x	x	x	x	Ammonium salts produced can be used to produce SO2, SO3 etc.
- Citrate & Stauffer processes	x	x	x	x	x	x	Recover solid molecular sulfur - proprietary processes.
- Pearson-Peck process	?	x	x	x			Uses phosphate mineral to produce fertilizer - needs nearby supply of mineral and market for fertilizer.
- Tail gas cleaning	?	x	x			x	Variety of proprietary processes available - used on refineries and steel mills.
- Irradiation technologies	x	x	x	x	x	x	Gamma ray, electron beam and UV irradiations under development. Large scale not demonstrated.
Dry FGD systems							
- Dry lime injection	x	x	x	x	x	x	Powdered lime injection - collected in filter - Efficiency depends on ratio lime/SO2 and size of lime.
- Spray drying process	x	x	x	x	x	x	Spray of lime or alkali injected - dries on contact - collected on filter - better efficiency than dry system.
- Poli- Process	?	x	x	x			Regenerative system - absorbs on phosphate rock - SO2 regenerated, converted to SO3, reacted with rock to form low grade fertilizer. Needs nearby supply of mineral.

NOTES :-

x - could be used in most instances.
xx - might be suitable for some industries but unlikely value on small boilers.
? - of use in a few cases only due to need for convenient supply of mineral absorbent.
$ - Currently In use
- blank denotes - not applicable

Table 2.1B

AVAILABLE ABATEMENT CONTROLS - NO_x

NO_x CONTROL	General Industry Sectors	Falcon-bridge	INCO	Algoma	Ontario Hydro	Refin-eries	COMMENTS
Pre-Combustion Controls							
Fuel switching	x				x	x	Oil switching equivalent to ref'n'y desulfurization, use of Nat. Gas universally is not practicable.
Fuel modification					x		Can be applied by major sources only -
Combustion Controls							
Low Excess Air	x			x	x	x	NOx reduction dependant on fuel type.
Flue gas recirculation	x			x	x	x	Suitable on limited range of boilers, heaters and incinerators
Staged combustion	x			x	x	x	Not suitable for gas burning
Low NOx burners	x			x	x	x	Suitable for oil or gas combustion
Lime injection modified burner	••				x		Used on pulverized coal burners - under development - costs and efficiencies uncertain.
Dry lime addition to fuel	••				x		For coal fired boilers, with grates, and incinerators - very low efficiency for NOx.
Fuel additives (catalytic)	x				x		Negligible efficiency unless excessive amounts of expensive additives used.
Emission Controls							
Selective Noncatalytic Reduction	x			x	x	x	Generally applicable but narrow temperature range limits usefulness
Selective Catalytic Reduction	x			x	x	x	Broader temperature range and higher efficiency than SNCR.
Copper oxide absorption	x			x	x	x	Insufficient cost information available
Irradiation technologies	x	x	x	x	x	x	Combined NOx/SO_2 removal - under development.
Other combined technologies	x			x	x	x	No reliable information on NOx removal. Insufficient effectiveness and cost information available.

NOTES :-

x - could be used in most instances.
xx - might be suitable for some industries but unlikely value on small boilers.
• - Used as part of overall emission reduction program.
•• - Suitable for solid fuel burning operations
- Blank denotes not applicable

Nonmetallic Mineral Product	Clothing Industries
Chemicals and Chemical Products	Machinery Industries
Food and Beverages	Printing and Publishing
Textile Industries	Wood Industries
Metal Fabricating	Electrical Production
Paper and Allied Products	Miscellaneous Manufacturing
Other Major Groups[1]	
Rubber and Plastics**	

[1] The sector listed as other major groups includes municipal and sewage sludge incinerators, commercial enterprises and institutions such as hospitals and universities.

** SO_2 emissions only

2.2.1 SO_2 Control

Pre-Combustion Control

Coal cleaning, petroleum fuel desulphurization, fuel switching, ore beneficiation and process and operating changes (see p. 2-4) are pre-combustion control methods of reducing SO_2 emissions. The techniques of petroleum fuel desulphurization and fuel switching are the methods of control considered in this report.

Coal Cleaning

The use of coal cleaning although a viable option on the large scale is not a relevant option for Ontario, except perhaps for its use by Ontario Hydro. The costs are comparable to the increased cost of purchasing lower sulphur coal but both are very dependent on the availability of suitable coals under the existing marketing and purchasing conditions. In turn both are comparable to the costs of wet scrubbing of flue gases (which are sensitive to specific site conditions) . Efforts to distinguish between the costs of these three techniques would be subject to errors which would be equal to or greater than

the estimated differences in costs (See also MOE Source Book 1983 and an MOE internal study (Barrow - Air Resources Branch).

Since the flue gas cleaning technologies are suitable for use on a wide variety of sources, these methods have been selected for the purposes of this study. These technologies can also be used to achieve a range of sulphur removal efficiencies and are more flexible than either coal switching or coal cleaning. Costs for coal switching are difficult to estimate and cannot be considered on a long-term basis.

Petroleum Fuel Desulphurization

Petroleum fuel desulphurization would likely be achieved by regulating the sulphur content of fuel oils. The necessary increased availability of low sulphur fuels would be achieved, in practice, by refinery fuel desulphurization. The cost of switching to low sulphur oils would be very dependent on market forces and difficult to assess. The costs of fuel desulphurization can be more directly evaluated, and has been selected as the more reliable method of estimating costs. As a side benefit low sulphur diesel fuels would also increase engine life and achieve some cost savings.

In this report the costs of fuel desulphurization are based on a study by MGH International (1983) (see Section 3.2.1) which describes technologies to treat crude oil to obtain a sulphur level of 0.3% in Light Fuel Oils (LFO) and 0.5% in a reduced output of Heavy Fuel Oils (HFO). Of a number of studies on fuel desulphurization, including studies by MHG and number of studies related to sections of refineries, the selected study was chosen as being directly applicable to Canadian refineries. It encompassed all of the refinery operations. The above specifications were assumed to be achieved by the following processes:

- fixed bed hydrotreating followed by an amine treatment plant and sulphur recovery unit
- residual thinning of atmospheric and vacuum still bottoms

- desulphurization of middle distillate to 0.3% sulphur
- residual oil desulphurization using H-oil or equivalent process.

Fuel Switching

Fuel switching from coal or oil to natural gas would achieve a major reduction in SO_2 emissions and costs have been estimated for this method of emission reduction. As noted later in Chapter 3 (Section 3.2.1), the method has severe practical limitations and the possibility of its widespread use needs careful consideration.

Ore Beneficiation

Techniques similar to those employed for coal cleaning can be used for the reduction of SO_2 emissions from metallurgical processes. These are beneficiation processes which result in the removal of unwanted sulphur bearing compounds from the ores, before they are subjected to the various smelting, sintering and refining processes. They are currently being used at the nonferrous smelters and could be of value at the Algoma plant in Wawa. Costs have been estimated for this process in Section C.3.3.

Process and Operating Changes

Process changes are specific not only to the types of processes in use, but to actual process details. They may affect product quality as well as process costs. Except for those combustion modifications to boiler operations which have been identified and to refinery operations influenced by fuel desulphurization it has not been possible to determine the costs of process changes because of limited process information in the inventory.

Combustion Control

A number of methods have been proposed for the introduction of chemicals into the fuels or onto the grates for the control of SO_2 emissions. These may generally be defined as low efficiency systems. They are described below.

Fuel Additives

Additives, usually intended to possess catalytic qualities, have for many years been used to reduce fouling problems, promote combustion, and ensure the complete oxidation of some heavy metals, such as vanadium, so that the volatile compounds or elements are converted to nonvolatile forms which remain in the boiler rather than being emitted as fly ash.

In recent years it has been claimed by some suppliers that these materials will serve to convert SO_2 to SO_3 which will react with the fly ash and be retained in the particulate emission control system. Examination of supporting data indicates that the SO_2 containment is directly related to reaction with the additive.

These additives are intended for addition at rates of under 0.1% of the fuel rate. At these rates they are ineffective for SO_2 control. If they are used in quantities that are effective the cost of the additive becomes extremely high and expanded particulate emission collection systems will also be required. SO_3 may have to be used as an additive to maintain high ESP particulate removal efficiency when low sulphur western (Canadian) coal is used as fuel. It is not however used to reduce SO_2 directly.

Dry Lime Addition to the Fuel

Tests have been made of adding lime to solid fuels in coal boilers and incinerators. Efficiencies of above 20% have been recorded but the problem of distributing the lime evenly amongst the fuels and ensuring that the necessary intimate mixing of lime and fuel is achieved result in variable and generally poor efficiency of control.

Lime Injection Modified Burners

Furnace injection is a developmental process in which limestone, or hydrated lime, is injected directly into the furnace of a coal-fired boiler. The reagent is calcined to calcium oxide (CaO) which reacts with sulphur dioxide

to form calcium sulfate ($CaSO_4$). The unreacted lime (CaO), $CaSO_4$, and fly ash are then collected together in a fabric filter or electrostatic precipitator. Ontario Hydro and others have programs underway to further develop this process.

The drawback to the process is that it has limited SO_2 removal efficiency. Its main advantage is that it can easily be retrofitted to existing plants at relatively low cost. A number of problems exist which require to be resolved for each installation. These include the possibilities of fusion of the lime, deposition of the lime on furnaces walls and deposition on boiler tubes. This method of control is therefore not yet suitable for consideration as a generally applicable process.

Some of the problems associated with the addition of lime to fuel beds have been partly overcome, for pulverized coal burners, by the addition of lime to the fuel at modified burners. The lime is thus introduced directly into the flame zone, resulting in improved removal efficiencies of above 20%. Ontario Hydro has achieved between 40 and 50 percent SO_2 removal in full scale testing and there seems to be potential for even higher efficiencies.

Fluidized Bed Systems

These systems burn solid fuels in a heated bed of sand which is agitated by a stream of air applied in such a manner as to maintain the bed in a semi-fluidized state. The fuel is injected into the bed of sand where it is burnt in the air stream. Although the fluidized bed needs to be preheated with a gaseous or liquid fuel, the heat of combustion of the solid fuel maintains the bed temperature during its normal operations. The agitated bed serves to grind the ash and other noncombustibles preventing clinker formation in the bed.

These systems are also used for the incineration of solid wastes. However, operating costs are high, and although the injection of lime to reduce

emissions of SO_2 has been shown to be feasible the ash carryover rate is high and a high efficiency of ash removal is necessary.

A change to a fluidized bed boiler would require a complete change of the furnace involving high capital and operating costs. Some reduction in costs might be obtained by the use of pressurized units, which would be smaller and more efficient but considerable development work remains before these systems become commercially viable.

The fluidized bed systems are therefore considered to be of value when new installations are contemplated but too expensive for the reduction of existing emissions since a complete boiler replacement would be required.

Emission Controls

Wet Flue Gas Desulphurization (FGD)

Wet scrubbing FGD systems absorb the SO_2 from the gas stream into a solution or a slurry of an alkaline chemical forming a sulphate. The most widely used systems employ lime or limestone as the alkaline reactant. Other processes use magnesium, sodium or ammonia (Cominco process) to react with the SO_2.

Once a salt has been formed the material can be discarded (throwaway processes) or a recoverable product can be obtained. This may take the form of SO_2 (regenerative processes), sulphur or another sulphur containing material.

The processes resulting in a recovery of the sulphur are generally more costly than the majority of the throw away processes since they require additional treatment stages and often use more expensive chemicals. They are normally economically better than the systems which discard the product only if: waste disposal costs are significant; the recovered material can be used, on-site, to reduce the purchase of a raw material; or if a ready and economically favourable market for the product is available.

Unfortunately the markets for sulphur, sulphuric acid and other products are cyclical and volatile in their activities. To remain economically preferable to the throwaway systems a firm contract for purchase of the product must be obtained or else the storage costs of holding the product, until a suitable market opportunity, arises become uncertain or prohibitive. On the other hand, the cost of acceptable waste disposal has increased significantly and is likely to increase further in the future; leachate from inadequately constructed landfill may allow hazardous trace metals such as lead solubilized by alkali in the ash to reach the environment. Stringent new waste disposal measures would significantly increase costs. This issue has not been considered in the process costing.

Apart from the use of recovery processes at locations such as pulp mills, (where the recovered SO_2 can be used in the process), and the nonferrous smelters, (which produce emissions with an SO_2 content above >2.5% suitable for making sulphuric acid) the use of throw away systems has been identified as the most suitable wet control method for SO_2 reduction.

These processes use slurries of lime or limestone and the problems of scaling corrosion and erosion, originally associated with them, have been amenable to a variety of process improvements. Within the accuracy of the estimates, the use of one or other of the reactants cannot be demonstrated to be economically preferable. This study has therefore used the more widely applied limestone process as a basis of the cost estimates for the throw away systems. They are capable of over 95% removal of SO_2 although they are generally designed for operation at that efficiency.

Special processes such as the Pearson-Peck process (MOE 1983) have been proposed for specific applications but their requirements of minerals as absorbents limits their usefulness for general application. The costs of installing and operating these processes can only be assessed for specific locations. They have not been evaluated for this study.

Tail gas cleaning is employed at petroleum refineries and steel mills. Several proprietary processes (including the Beavon, Bureau of Mines Citrate and Scot processes) are available, but their application for the purposes of this study would require a more detailed identification of the sources and the existing operation at the various plants being considered than is available from the inventory. These processes have therefore been excluded from the options being considered.

Dry FGD Systems

Dry scrubbing FGD systems have not been used the same length of time as wet systems, but, they are becoming prevalent with power utilities, industries and municipalities. In these systems, absorption of SO_2 and other acid gases takes place when the flue gas comes in contact with a sprayed dry or slurry sorbent. The water content of the slurry evaporates and the mixed salts and flyash are removed in a particulate collector downstream. If a baghouse is used to collect the particulate some additional chemical reaction between collected dusts and unreacted acid gases may take place, thereby further enhancing acid gas removal.

For the dry spray systems both sodium and calcium-based sorbents can be used. Common sorbent materials include nahcolite (natural sodium bicarbonate), trona (sodium sesquicarbonate), synthetic carbonate/bicarbonate mixtures, and pressure hydrated lime. Compared to wet systems, the advantages of dry spray systems include simplicity, increased reliability, lower cost and and easier retrofit.

A process for the absorption of SO_2 on phosphate rock is available in the U.S.A. The process, known as the Poli-process (MOE 1983), has been suggested for use at Algoma. The absorbed SO_2 is regenerated and converted to SO_3 which can then be used to produce sulphuric acid or to form a phosphate fertilizer. The fertilizer is not considered to be suitable for use in Ontario, and the costs are similar to those for wet scrubbing FGD systems. Its economic applicability is also related to the availability of cheap phosphate rock. It

can therefore only be considered as suitable for use at locations adjacent to phosphate deposits. It has not been considered in this study.

Irradiation technologies, using a variety of particle and ultra-violet radiations, have been investigated for the conversion of SO_2 and NO_x emissions to solid compounds in the presence of ammonia. The chemistry is not well established but ammonium sulphate and ammonium nitrate are two of the products. Large scale applications of these processes still needs to be demonstrated before adequate design and cost information is available.

2.2.2 NO_x Controls

Pre-Combustion Controls

Fuel Switching

The use of nitrogen free fuels such as natural gas or distillate oils results in reduced emissions of NO_x by eliminating the fuel derived component of the emissions. The thermally produce NO_x would still be formed. The high flame temperature obtained using these fuels would offset some of the reduction if coal or residual oil were to be replaced by these fuels.

Conversion of combustion sources to natural gas could be carried out for some sources, but the province wide conversion of all sources is impracticable due to logistical problems and the economic impacts, which would follow. Switching from residual oil to distillate oils could be accomplished by the desulphurization of refinery fuels. The conversion of coal burning units to oil burners would require major changes to the units.

Fuel Modifications

In addition to the fuel modifications obtained by refinery fuel desulphurization treatment, processes exist for the conversion of coals to liquid or gaseous fuels. These processes require complex and large plants;

they cannot therefore be applied to the small commercial and industrial sources individually.

Ontario Hydro could conceivably install such a plant but the costs and the reliability of these processes have not been well established on the intermediate scale required for a power generating station.

Combustion Control

In combustion, two mechanisms are at work creating NO_x. "Thermal" NO_x is created when atmospheric oxygen and nitrogen combine at the very high flame temperatures. "Fuel" NO_x is produced by a second mechanism, the reaction of fixed fuel nitrogen and oxygen in the combustion air.

Each of these NO_x producing mechanisms requires somewhat different methods of control. Thermal NO_x production rates are affected by the flame temperature, the amount of excess oxygen available and the residence time in the peak flame zone. Fuel NO_x production is more dependent upon the amount of fixed nitrogen in the fuel, the amount of oxygen available for oxidation of the fixed fuel nitrogen and on the presence of local oxygen-rich pockets within the fuel/air mixture. Unlike thermal NO_x, fuel NO_x is not very dependent upon flame temperature.

Combustion modifications can reduce NO_x emissions by: limiting the residence time in the primary flame zone; reducing the flame temperature, and by reducing the rapid mixing of fuel and secondary air. Several combustion modification methods are available and these are described below.

Lower Excess Air (LEA)

One method of reducing NO_x concentrations involves lowering excess air rates to result in about 1 percent O_2 in the exhaust gas. To date this method has not been as effective as two-stage combustion; it also increases the risk of

explosions. For practical reasons the cost studies have used 3% excess O_2 (15% excess air)

Low NO_x Burners

Low NO_x burners hold promise as a means for significantly reducing NO_x emissions. They are designed to control the air/fuel ratio in the burner area thereby retarding the formation of NO_x from fuel bound nitrogen and partly reducing thermal NO_x. Their use under the most advantageous conditions permits NO_x emission reduction of up to 60 percent without compromising burner efficiency. They are relatively easy to retrofit and existing burners can be modified or replaced without major changes to a furnace. However, their effectiveness is dependent on boiler configuration and generalizations are difficult to make.

Staged Combustion (SCA)

An effective NO_x-reducing method applied to steam generators involves the splitting of combustion air. With this method, only 90 to 95 percent of the combustion air requirement is injected at the burner while the remaining air is introduced a few feet downstream. This delayed air introduction is found to reduce NO_x concentrations in flue gases by 40 to 50 percent. Staged combustion has been limited to large sources. It has not been demonstrated on small units.

Flue Gas Recirculation (FGR)

In order to reduce the concentration of oxygen and to lower the temperature in the combustion zone of boilers and incinerators a side stream of the flue gases is recirculated to the combustion air inlet ports. This results in a reduction in the quantity of NO_x produced by thermal reactions. The efficiency is dependent on the boiler or incinerator configuration but is in the range of 10-30%. Costs are also dependent on the specific installation. When other

control techniques are applied its effectiveness is diminished; it is therefore used only when other methods are not applicable.

Emission Controls

Numerous flue gas (post combustion control systems) NO_x control processes have been developed but only two have reached commercial development - selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR).

Selective Non-catalytic Reduction (SNCR)

The SNCR (thermal deNO_x) process relies on NO_x reduction by ammonia addition and the application of high temperatures (1600°F to 2000°F). It is a good method for reducing NO_x beyond the range achievable by combustion modifications. Its advantages include the fact that control equipment does not become fouled when dirty fuel is used, there is no catalyst which can be poisoned by dirt and sulphur compounds, boiler changes are not required and there is no increase in the incidence of tube corrosion or incomplete combustion.

Compared to SCR, SNCR has a lower NO_x removal efficiency because of lower selectivity and greater sensitivity to furnace load changes. SNCR has a lower capital cost than SCR.

Selective Catalytic Reduction (SCR)

The SCR process relies on ammonia, in the presence of a catalyst, to reduce NO_2 to N_2 and water vapour. Its reactions are basically the same as for SNCR, however, there are many more process variations due to the effects of different amounts of flyash in the process equipment. Compared to SNCR, SCR attains higher NO_x removal but is more costly, is affected by dirty fuels and is more difficult to retrofit.

Combined NO_x and SO_2 Control

The FGD systems which result in the removal of SO_2 generally will result in the simultaneous reduction of NO_x emissions. Unfortunately studies of these systems have been confined to the measurement of SO_2 reduction efficiencies and the NO_x removal capabilities have not usually been publicly reported. This study has therefore not used combined SO_2/NO_x technologies but a brief description is given for one of these technologies.

Fluidized-bed Copper Oxide Process

The U.S. Department of Energy has developed a fluidized-bed copper oxide process for cleaning SO_2 and NO_x. It involves passing hot flue gases into a fluidized bed containing a thin layer of copper oxide supported on aluminum oxide pellets. The copper oxide reacts with the sulphur in the gas stream, trapping it as a copper sulfate in the pellets. Regeneration permits elemental sulphur to be recovered and nitrogen oxides are destroyed by reacting them with ammonia injected into the combustion gases. Water and nitrogen are the primary by-products.

Other Technologies

Combined SO_2/NO_x control methods include the use of lime injection, lime addition to the fuel and the use of fuel additives. Primarily aimed at SO_2 control their efficiencies for NO_x removal have not been recorded although lime injection through the burners may have some effect by absorbing NO_x as it is formed. The reactivity is low and these methods are not considered to be suitable for NO_x reductions.

2.3 Major Point Sources

2.3.1 Falconbridge

In the late 1970's, Falconbridge undertook a major smelter modernization with

associated pollution control components. As of 1985, the company SO_2 emissions were below the 1994 Ontario Regulation of 100 kilotonnes per year.

SO_2 Controls

The methodology proposed for sulphur dioxide abatement by Falconbridge Limited includes:

- increased degrees of roasting in fluid bed roasters to produce additional sulphuric acid
- converter slag cleaning
- increased pyrrhotite rejection in the Strathcona Mill

The methods for control of future SO_2 emissions at this location are described in section 3.3. They would be based on throwaway or regenerable FGD technology.

NO_x Emissions

The major sources of NO_x emissions at Falconbridge in 1987 were reverberatory furnaces and converters.

The company currently employs electric furnaces and hence its NO_x emissions have been reduced by approximately 64 percent. Therefore no additional controls were considered for this source.

2.3.2 INCO

SO_2 Controls

The regulated 1994 emission level for Inco is 265 kilotonnes. To achieve this limit the proposed methodologies for SO_2 reduction include:

- increased pyrrhotite rejection
- oxygen flash smelting/matte processing

- the capture of fluidized bed roaster off-gases
- upgrading of the existing acid plant or building a new acid plant

The methods available for control of SO_2 emissions to below the 1994 target level are described in section 3.3.2. They would be based on throwaway or regenerable FGD treatments.

NO_x Controls

The largest sources of NO_x emissions at INCO are reverberatory furnaces which account for approximately 86% of the total. The remaining sources of NO_x emissions are boilers.

INCO is proposing the use of oxygen flash furnaces in place of reverberatory furnaces. With the implementation of this proposal furnace generated NO_x emissions would virtually be eliminated.

2.3.3 Algoma

According to the company progress report filed with the MOE in 1985, Algoma identified five control technologies which would help reduce its SO_2 emissions. At the time of filing this report however, the company noted that unless there was a major change in its economic circumstances the most likely method of achieving 1994 abatement requirements would be either reducing production capacity or utilizing alternative ore sources. However, the following technologies were reviewed in terms of post 1994 reductions.

SO_2 Control

Pre-combustion, process changes and emission controls were considered. Of these ore beneficiation was used in this study but process changes were not because of limited information. Most of the emission controls shown in Table 2.1, including:

- Limestone flue gas desulphurization
- Bureau of Mines Citrate Process
- Pearson-Peck Process
- Poli Process; and
- Cominco Process

were considered. Limestone flue gas desulphurization was selected because it is a well established, proven technology for which there is good data. As discussed in Section 2.2.1, Emission Controls this system is appropriate for large emitting sources and has an efficiency upwards of 90 percent. The prime reason for not selecting regenerative systems was a lack of information on markets for the by-products.

NO_x Control

The sinter strand process can be controlled for NO_x emissions by the use of catalytic and non-catalytic reduction processes. Since the flue gases are exhausted through an electro-static precipitator, the likelihood of the catalyst being fouled by particulate matter, which has been experienced with catalytic processes, is reduced.

Process modification such as partial recycling of the flue gases has very limited value for a process such as this which is only partially enclosed.

Algoma's sintering plant at Wawa is not one of the major NO_x emitters in Ontario. The costs of control have therefore not been included in this study.

2.3.4 Ontario Hydro

SO_2 Control

Several alternative Flue Gas Desulphurization (FGD) technologies are currently being considered by Ontario Hydro. These include:

- Wet Limestone Slurry Process
- Limestone Dual Alkali Process
- Lime Spray Dryer Process
- Lime Injection Modified Burners (LIMB)

At the moment process selection studies are being conducted by Ontario Hydro along with an environmental assessment report on flue gas desulphurization. These processes are the same as those described in sub-section 2.2.1, Emission Controls, and are not repeated here.

NO_x Control

In coal-fired boilers, fuel generated NO_x predominates over thermal NO_x. NO_x control strategies of potential value to Ontario Hydro are outlined below. Detailed discussions of these strategies are presented in Section 2.2.2 and will not be repeated here.

Pre-combustion control techniques which may be used for fuel modification include fuel switching, fuel additives, and fuel denitrification. All of these are somewhat experimental at the moment and are not as yet proven to be effective.

Several combustion modification techniques may also be used singly or in combination on coal-fired utility boilers. These include low excess air (LEA) firing; staged or off-stoichiometric combustion (SCA); low NO_x burners (LNB); and flue gas recirculation (FGR). At present Ontario Hydro has replaced all burners at Nanticoke thermal power station with low NO_x burners. Low NO_x burners are also considered for Lambton and Lakeview generating stations.

Of the two flue gas treatment processes (SNCR and SCR) the choice for Ontario Hydro will be dependent on the relative costs of controlling fewer sources using the more efficient SCR process and the cost of controlling more sources with the SNCR process. The various costs will be dictated by the increased degree of control which can be achieved at each of the power stations. Site

specific conditions at the stations will have a significant bearing on the costs. Such a degree of sophistication is not possible under the terms of reference of this study and costs have been developed on a more generalized basis of using the more efficient SCR technology applied at 500 MW units. In part this decision was also influenced by the availability of cost information, which was more readily available for this technology and unit size.

By controlling the emissions from individual units any desired level of control can be achieved up to the maximum obtainable reduction of about 90%, if all units are controlled by the use of SCR at high efficiency (SRI International 1980).

3.0 SELECTION AND COSTING PROCEDURES

3.1 Introduction

The procedures used in the estimation of control costs, which will be described in this chapter, have been derived from several sources. The basic programs have followed the general procedures shown in the U.S. EPA Economic Analysis Branch (EAB 1987) report, but the factors and exponents used have been modified to follow those in Calvert & Englund (1984) and Radian Corporation (1984). Where the data appeared to be inconsistent or lacking, comparisons were made with generalized information available in the literature. Use was made of AP 42 (1985) for comparing emission rates and flow quantities and Perry & Chilton (1984) and Fryling (1967) for information about fuel heating values and sulphur content.

Capital and operating costs were estimated and annualized costs calculated for a per tonne basis of SO_2 and NO_x. The algorithms used for estimating the costs of control are given in Appendix B.

3.2 Industrial Sectors

For the purposes of this study sources which emitted less than 10 tonnes per year of the pollutants were excluded from the assessments. In addition, some sectors which contained only small sources of a pollutant were eliminated from the study for that pollutant. Less than two percent of the emissions were thereby left out of the study's evaluations.

To establish costs for an industrial sector the types of processes and boilers were sorted into representative groups within each sector. The geometric means of the emissions from the groups were determined and a representative flow rate was estimated from the available data and was augmented by use of the EPA emission factors. The costs of control of this representative source were obtained and the overall costs for the group obtained by multiplying those cost by the number of sources in the group.

The costs for the industrial sector were then obtained by addition of the costs of the groups within the sector.

In identifying suitable groupings, the boilers were separated from the process sectors and were subdivided according to the fuel used. The process sources were grouped in accordance with either the processes to be controlled or the methods of control which could be applied to the process.

Some identified costing methods include the cost of retrofitting the technology, e.g. for combustion modifications on boilers no additional retrofit factors were used. In other cases retrofit factors are not included in the direct estimates. A factor of 1.2 was applied in these cases except that of Selective Catalytic Reduction for NO_x control. This technology, which operates at about 800° C requires the installation of a large catalyst bed in the exhaust gas stream between a boiler and any downstream heat recovery or cooling system. To install this bed it is necessary to divert the gas flow from its normal duct to the catalyst bed and then return the treated gases to the normal channel. In the case of process streams the exhaust gases will generally need to be heated to the required catalyst operating temperatures. The costs for these modifications could be large. A retrofit factor of 1.4 has therefore been applied to these situations.

3.2.1 Boilers

Sulphur Dioxide

In addition to the use of flue gas desulphurization methods, the SO_2 emissions from boilers can be reduced by changes to the fuels used and by injecting lime directly into the furnace. Two cases of fuel changes have been assessed; switching to natural gas and the use of low sulphur oil fuels to replace coal and high sulphur oils.

The use of low sulphur fuel oils has been assumed to be achieved by means of

fuel oil desulphurization at the petroleum refineries since, as described earlier, widespread demands for low sulphur fuels would require that the refineries responded in the proposed manner or a similar one. The costs for each case have been allocated to the sectors on the basis that the emissions presently inventoried, when ratioed to the total emissions from the oils now produced by the refineries, result in the fractions of the total SO_2 reductions (Table A-4.11) which can be applied to the sector. The cost to the sector can then be obtained from the cost/tonne SO_2 removed (Table A.4.12). The cost equation used for HFO being changed to light fuel oil under case 6 is:

$$\text{Cost} = \frac{\text{Emissions from sector (HFO)}}{\text{total emissions from (HFO)}} \times \frac{SO_2 \text{ reduction for Saleable (HFO)}}{\text{[TABLE A.4.11]}} \times \frac{\text{Cost}}{\text{tonne } SO_2 \text{ removed}} \quad \text{[TABLE A.4.12]}$$

$$= \frac{\text{Emissions from sector (Residual)}}{139,323} \times 123,426 \times 510.1$$

The costs to the refineries are based on the reduction at the refineries (Table A.4.12) multiplied by the cost per tonne SO_2 removed. It should be noted that some of the costs of the overall reduction in emissions may be borne by sales outside the Province.

The study from which the cost data were taken assumed a nominal 0.3% sulphur content for the light fuel oil fraction currently produced. Although the present situation is that oils containing up to 0.5% sulphur are being produced, the refineries are capable of supplying 0.3% sulphur contents and this value has been used in this study and, in the past, by MOE when it was necessary to estimate emissions, from oil consumption, for inclusion in the inventory. The costs developed by MHG have therefore been used for this section of the study. It should be noted that in Case 5 the study by MHG indicates a slight increase in the sulphur content of LFO, due to increased loading of the H-Oil process.

Although it is not considered to be feasible for widespread application, costs have been developed for fuel switching to natural gas based on the fuel used and heat content of the fuel (Appendix B). An additional benefit of this substitution would be somewhat lower NO_x emissions for the sources considered because of the elimination of fuel nitrogen. The annualized costs generally indicate that the switch can be made at an overall surplus. However this indication is based on general fuel costs for 1987 supplied by the fuel industries (Appendix B). The actual value or cost of switching could be significantly different if fuel prices change either under external market forces or because of the direct impact of a regulated change of fuel on the markets or on the distribution costs of the fuels. The supply of natural gas in the quantities needed for a province wide change would require a major increase in the distribution pipeline system.

The FGD systems used in the evaluation have been dry lime scrubbing, spray dry lime scrubbing and wet scrubbing with limestone using the algorithms shown in Appendix B.

Nitrogen Oxide

Reductions in emissions of NO_x can be achieved by changes to the boiler furnace operations or to the fuel burners. The simplest to install are burner changes from the older systems to the more efficient low excess air burners. This change is limited in its application to gas and oil burners, it cannot be applied to coal, wood or refuse burning installations. However reductions in the amount of excess air supplied to the system can be made in all cases and the emissions reduced thereby. In order to carry this out, some changes need to be made to the boiler control system and costs apply to these modifications. The extent of the emission reduction will be dependent on the boiler type, the assumed levels are shown in the table below:

Boiler type	Original Excess Air	Modified Excess Air
Natural gas	40%	15%
Fuel oil	40%	15%
Coal (pulverized)	50%	30%
Coal (stoker boilers)	50%	35%

Modifications to the combustion chamber and the manner in which the combustion air is introduced to the burning area can be applied to all types of boilers and involves the redistribution of the air between the ports and in most cases a change in the position of the ports. It may also include the use of flue gas recirculation. The costs are therefore extremely variable between the different boilers which exist. A generalized boiler design was used in the estimates which was based on the heat input to the boilers, average heating values of the fuels, and the excess air levels shown above. These values in turn were based on the data from the inventory, where it was available, or on estimates based on those values which were inventoried. In making these estimates reliance was placed on the use of normal heat and mass balance calculations and "emission estimates" from the U.S. EPA (1985).

It has been assumed that none of the existing boilers have been upgraded and the cost estimates include changes for all of the boilers within the appropriate groupings. For this purpose the boilers within each sector were grouped according to the fuels used.

Tail end control systems for boilers which were examined included SCR, SNCR, copper oxide and carbon catalyzed systems. Since they have been sufficiently well tested for reasonably good cost estimating procedures to be developed, the SCR and SNCR processes were used for this study.

The cost models used for estimating SNCR and SCR costs were based on algorithms given by SRI International (1980). The input to the calculation was obtained in similar fashion to that for combustion modifications and relied in some instances on the interpretation of data from the inventory rather than on the directly available information. Flow rates or heat input were used to obtain equivalent MW capacities and the costs were then prorated from the SRI report.

The approach taken did not vary between the sectors, hence although errors may exist in the estimates, direct comparisons between the sectors should be valid. The algorithm used is given in Appendix B.

3.2.2 Processes

Sulphur Dioxide

The process sectors emitting sulphur dioxide are frequently combustion sources using waste gases from the process sectors for process heating or steam production. In those cases assumptions have been made based on reported compositions, heat contents (Appendix B) and fuel usage rates calculated from the SO_2 emissions. Fuel switching has not been used nor has the use of natural gas for the process streams since the impacts on the process operations could not be readily assessed. FGD processes have been used for control of process emissions throughout this part of the study. Regenerative SO_2 scrubbing has been applied to the pulp and paper sulphite mills where the liquors can be collected and reused in the pulping process. Throwaway scrubbing processes have been applied to all other sources. The algorithms for these control technologies are shown in Appendix B.

Nitrogen Oxides

NO_x emissions from processes arise mainly from combustion sources, but can in a few instances occur as a result of chemical reactions. The combustion sources are in general amenable to the same control techniques as are the

emissions from boilers. The major difficulty in estimating the costs of controls arises from a lack of information about the manner in which the combustion is carried out and the heat content of the fuel used for combustion. The sources are varied, and the emissions may occur as the result of using normal fuels or fuels produced in the processes. The combustion of coke oven gas, CO gas and the incineration of wastes all result in emissions of NO_x. It was not always possible to identify the source of the fuel used directly from the inventory and in many cases the exact composition of the fuel could not be established.

In order to indicate the assumptions made and the accuracy of the estimates more clearly the industry sectors will be described separately in the following segments of this section.

3.2.3 Specific Sectors

Primary Metals

Sulphur dioxide emissions from these sources arise as a result of the reduction of ore by combusting the metal sulphides. In view of the high emission rates which such processes give rise to, an efficient control method will be needed if acceptable levels of SO_2 are to be achieved. The lack of detailed knowledge of the processes involved and the complex nature of the metallurgical operations prohibited the evaluation of process changes being used to control the emissions. Wet limestone scrubbing was therefore costed as the means of achieving the desirable emission control efficiency.

The only source of NO_x listed under this category was Kidd Creek Mines Ltd., which, although recorded as emitting 669.5 tonnes/ year has instituted controls and is now considered to be a negligible source of this pollutant.

Food, Beverages and Textiles

Sulphur dioxide emissions arose from only one process source, Canada Malting (Tor) Ltd. which used residual oil for its barley malting heat source.

Only two significant process sources of NO_x emissions were listed in the inventory for this sector. These both used fuels for drying foodstuffs, they were therefore treated as if the emissions were from boilers and were subjected to the same NO_x control systems.

A large inventory of boilers gave rise to NO_x and SO_2 sources. There were 24 sources using natural gas 4 using distillate oil and 14 which employed residual oil.

One other source of SO_2 and NO_x was included in this inventory, probably due to a coding error, which appears to be anomalous. Cyanamid of Canada which was recorded as using CO gas is included in the NO_x boiler tables as the source using "other" fuels. Cyanamid was omitted from consideration in costing SO_2 controls.

Rubber and Plastics

There were no process sources which emitted sulphur dioxide. Hence the only sources emitting this pollutant were the two oil consuming boilers.

The sources in this sector have no processes which give rise to NO_x emissions and only four boilers of significance. Two of the boilers used natural gas as a fuel, one used residual fuel oil, the fourth used distillate.

Textile Industries

Of the 11 boilers in this sector which emitted 10 or more tonnes/year SO_2 ten were using residual oil the other used distillate.

There were only eight of these boilers which gave rise to 10 or more tonnes/year NO_x emissions. Seven used residual oil and the other used natural gas.

The processes which emitted SO_2 were viscose rayon sources, while NO_x was emitted from a nitric acid plant.

Paper and Allied Products

The processes used in this industry were entirely from Pulp and Paper mill operations. Nitrogen oxides arose from the recovery boilers and the lime kilns while SO_2 was also emitted from the digesters, black liquor treatment plants, absorption towers and smelt dissolving tanks. Each type of source was treated individually, in particular the sulphite mill emissions from the lime kiln and the digester blow pits were assumed to be recoverable for return to the process and were controlled by wet scrubbing using caustic soda scrubbing. A number of "Miscellaneous" sources of SO_2 were assumed to be treatable by non-regenerable FGD technologies.

In addition to the use of natural gas and oil, the boilers in this sector used coal and wood wastes as sources of fuel. For the coal sources, the fuel was assumed (as it was throughout this study) to have a heating value of 30218 kJ/kg (13,000 BTU/lb) and 2.8% sulphur content. Wood waste properties were assumed to be 10,228 kJ/kg (4,400 BTU/lb) as fired and 0.05% sulphur.

Metal Fabricating

The processes in this sector were primarily those from which emissions occurred as a result of the combustion of fuels used to heat the metals, or ores. A major exception are the coke oven emissions where the process is a partial combustion of coal from which the coke is produced. The fuels are varied, and frequently are gases arising from other stages of the operations. These include coke oven gas and blast furnace gas. The fuel heat contents used in preparing data for estimating control costs were based on literature

references and on the ratios of SO_2/NO_x emissions. The fuel characteristics used are listed in Appendix B.

Transportation Equipment

No processes were found for this sector in the emission inventory. The boilers used natural gas, oil, and coal. In total there were 19 sources emitting 10 or more tonnes/year. Ten NO_x and nine SO_2 sources are of concern.

Non-Metallic Mineral Products

This industry sector included 23 processes which emitted NO_x and 16 sources of SO_2 in excess of the 10 tonnes/year levels. These were mostly cement kilns but included melting furnaces and cupolas, as well as two asphalt plants.

Since these were high temperature sources similar to boilers they were assumed to be adaptable to the same type of control technologies as were the boilers. The 16 boilers assessed included one which burned coal and one using coke as its fuel.

Chemical and Chemical Products

Comprising mostly petroleum refineries, the process emissions from this sector were mainly from the combustion of fuels used for process heating. In addition there were emissions from the sulphur plants and carbon black manufacture which gave rise to emissions of both pollutants and two nitric acid plants which emitted only NO_x.

The sector used a variety of fuels for the boilers most of which were identified in the inventory. In other cases it was possible to establish that process off gases had been used. Where the fuel source of the emissions was listed as undetermined, it was assumed that the fuels were oil fuels which were categorized into residual or distillate in accordance with the relative

levels of the SO_2 and NO_x emissions.

Other Major Groups

Incinerators and wood waste boilers were the components of this industrial sector which gave rise to process emissions. Included amongst them were municipal, sewage sludge, industrial waste and hospital incinerators.

In many cases the emissions of NO_x and SO_2 were too small to be included in the cost estimates, either because the installations were small or the emissions were already being controlled.

The boiler emissions included heating plants at hospitals, major commercial institutions and universities as well as the emissions from boilers associated with the incinerators.

3.3 Major Point Sources

3.3.1 Falconbridge

SO_2 Emissions

Although the proposed process changes may reduce the SO_2 emissions to below 100 kilotonnes/year, it has been assumed, for the purpose of costing further staged reductions of SO_2, that a reduction from 100 ktonnes/year will be required. The needed reductions have been costed on the assumption that it will be possible to treat separate streams of the exhaust gases by dry lime injection, using a spray-dryer, in order to finally achieve an overall reduction to 50 tonnes/year. For estimating costs it was assumed that concentrations of SO_2 in the exhaust gases, which range between 1% and 3%, would average 2.5% and the flow rate be that which would result in this concentration.

NO_x Emissions

The modifications proposed for the reduction of SO_2 emissions at Falconbridge will also result in the reductions of oxides of nitrogen to below 10 tonnes/year. Further reductions, of unknown extent, will also accrue from the installation of any control equipment which may be installed to reduce the SO_2 emissions to below the regulated levels. No further control of NO_x has therefore been proposed.

3.3.2 INCO

SO_2 Emissions

The remaining gas streams to be controlled at INCO are low strength sources ranging from acid plant tail gas to many sources of fugitive emissions. The task of identifying the conditions for the control of the individual streams was considered to be intractable within the bounds of this study. The sizes of the effluent streams and the length of the ductwork needed to capture fugitive emissions and direct them to a control system would have required an extensive study. For costing purposes the gas streams were treated as being the same as if they all arose from a power generating station and would be controlled by limestone scrubbing. A concentration of 25,000 ppm was assumed for this purpose. The estimation of operating costs included the assumption that a suitable location for sludge disposal could be found on the company property: the costs of transport and disposal of the sludges were therefore relatively low.

NO_x Emissions

As in the case of the Falconbridge operations, emissions of NO_x will be minimal after the changes at the INCO smelter are completed. No further control is proposed for this plant.

3.3.3 Algoma

SO_2 Emissions

Although numerous methods of controlling SO_2 emissions have been proposed for the Algoma sinter plant at Wawa, including the Cominco, Mag-Ox and the Pearson-Peck processes they are more costly than the limestone scrubbing process and or involve problems of disposing of the recovered products. Limestone wet scrubbing is efficient and cost estimates (MOE, 1983) indicate that, within the error of the estimates, it can be used at Wawa as cost effectively as the other processes.

For the purpose of this study a high degree of control was not necessary as reductions of up to 50% of the "status quo" emissions were required to be costed. Scrubbing half of the exhaust gas using the lime spray drying method was selected as the most suitable method of removing SO_2 for achieving an emission reduction of up to 30%. Scrubbing of the full stream would be needed to achieve higher degrees of control.

For low efficiency reductions in emissions, ore beneficiation is the most attractive method. Costs for this process were estimated from published costs of coal treatment plants, on the assumption that similar degrees of beneficiation could be achieved on ore and on coal. The coal cleaning process uses similar methods of treatment, viz. crushing, screening, flotation dense media separation and oil agglomeration, as those used in the metallurgical mining processes.

NO_x Emissions

Iron ore sintering at the plant is not considered to be a major source of NO_x emissions. Therefore, no further control is proposed for this plant in this study.

3.3.4 Ontario Hydro

SO_2 Emissions

After all options for conservation have been exhausted, the options for reducing emissions of SO_2 lie between fuel switching to lower sulphur coals and the increased use of nuclear power to various flue gas desulphurization techniques. The costs of fuel switching on the scale needed for Ontario Hydro are dependent on the contracts which can be established for the supply of the lower sulphur content fuels. These costs cannot readily be established until the necessary negotiations have been virtually completed, neither can the quality of the coals be identified. This option has therefore not been considered for Ontario Hydro, neither has a switch to nuclear power been considered since the time frame to build more stations far exceeds the study period.

FGD systems can be based on scrubbing many units at low efficiencies or fewer units at high efficiency. A quick review of the options has indicated that the higher capital and operating costs associated with many units makes the use of low efficiency systems undesirable.

A single technique of control, using limestone scrubbing, was selected for the reduction of emissions to regulated levels as well as for further reductions to 50% of those levels.

NO_x Emissions

Reductions of emissions to the regulated levels were estimated on the basis of

of SCR units being installed at suitable locations. Further step-wise reductions, to a level of 50% of the regulated quantity, were assessed using the most efficient reduction method of installing SCR units on an additional 500 MW of generating capacity.

4.0 COST OF EMISSION CONTROL AND DISCUSSION

4.1 Introduction

Cost estimates for the industrial sector sources have been estimated for various groupings of the companies within each of the eleven selected industrial sectors (section 2.2). The groups were chosen by selecting processes which were controllable by one emission control method. In each group overall costs were estimated by first determining the geometric mean of the emissions within the group, estimating the cost for control of a source exhibiting the mean emission rate and then multiplying the cost of controlling a source with the mean emission rate by the number of sources within the group. By the use of this procedure one or more methods of control were costed for every source in the eleven sectors with emissions of SO_2 and NO_x of 10 tonnes per year or more. Sources from which the emissions were less than 10 tonnes constitute less than 2% of the total emissions from the selected industrial sectors and were not considered. The detailed list of sources was provided in the emission inventory which forms part of Interim Report No. 1. This inventory differs from the ones used for other similar studies related to the CAP program in that the SIC codes are different, estimates made for those studies were based on information obtained from industrial source and were extended on the basis of employment statistics applicable to the sectors being studied.

The cost of controls on the four major industrial sources have been derived from information in the MOE "Source Book" (1983) and the Report of the Ontario/Canada Task Force (1982). This information has been supplemented by studies carried out by Ontario Hydro (1987, 1988) and the Progress reports on their abatement studies issued by INCO (1988) and Falconbridge (1988). Costs have been estimated for further emission reductions which might be achieved.

Cost summaries are shown in Table 4.1 to 4.4 for the major sources and the industry sectors. These are derived from data shown in the Tables of Appendix A.

TABLE 4-1

SUMMARY OF SULPHUR DIOXIDE REDUCTIONS
FOR MAJOR SOURCES

Source	Option	SOX Emissions (Tonnes/year)	% Reduction	Capital Cost (million $)	Operating Cost (million $)	Total Annualized Cost (million $)	Amount of SO2 Removed ('000 T/yr)	Annualized Costs per tonne SO2 Removed ($/tonne)	Annual Production Capacity
Inco		265000	Base Case						240 millions lbs nickel/year
		238500	10%	37.8	13.9	20.01	26.60	752.20	*(INCO, 1988)
		212000	20%	52.4	20.0	28.52	53.00	538.13	
		185500	30%	64.2	25.2	35.64	79.50	448.34	
		132500	50%	83.7	34.4	47.99	132.50	362.18	
Ontario		175000	Base Case						*99.4 million MWH at rated
Hydro		157500	10%	62.3	4.7	14.84	17.50	847.95	capacity (SENES, 1988)
		140000	20%	124.6	9.3	29.58	35.00	845.09	
		122500	30%	186.9	14.0	44.42	52.50	846.04	
		87500	50%	311.5	23.4	74.10	87.50	846.80	
Falconbridge		100000	Base Case						
		90000	10%	14.3	9.3	11.58	10.00	1158.21	
		80000	20%	23.4	22.2	25.95	20.00	1297.75	
		70000	30%	30.3	36.5	41.39	30.00	1379.60	
		50000	50%	42.5	71.4	78.30	50.00	1566.00	
Algoma		125000	Base Case	-	-	-	-	-	
		112500	10%	13.4	0.1	1.66	12.50	133.02	
		100000	20%	22.5	0.1	2.75	25.00	110.15	
		87500	30%	21.9	35.6	38.14	37.50	1016.99	
		62500	50%	27.2	48.0	51.19	61.25	835.84	
	Base Case	179231	-	-	-	-	-	-	
Impact	Case 2	169194	5.6%	2.07	-	6.99	10.04	304.70	
of	Case 3	156289	12.8%	372.00	-	91.60	22.94	841.30	
Refinery Fuel	Case 4	146432	18.3%	373.71	-	104.90	32.80	795.70	
Desulphurization	Case 5	152167	15.1%	415.37	-	71.02	27.06	557.90	
	Case 6	142309	20.6%	494.10	-	76.75	36.92	510.10	

TABLE 4-2

SUMMARY OF SULPHUR DIOXIDE REDUCTION BY INDUSTRY CLASS

Source	Control Option (*)	SOX Emissions (Tonnes/year)	% Reduction	Capital Cost (million $)	Operating Cost (million $)	Total Annualized Cost (million $)	Amount of SO2 Removed (T/yr)	Annualized Costs per tonne SO2 Removed ($/tonne)
Primary Metals		14219	1985 Level	-	-	-	-	-
	2-P	725	94.9	2.1	7.2	7.47	13493.83	554
Food/Beverage		1421	1985 Level					
	1-P	1401	1.4	0.4	0.2	0.28	19.89	14266
	2-B	614	56.8	161.2	50.1	71.29	806.90	88349
	5-B	570	59.9	11.9	5.2	6.76	850.94	7948
	1-P	420	70.4	0.6	-4.5	-4.43	1000.10	-4425
Textile		7359	1985 Level					
	1-B	4894	33.5	9.2	3.1	4.30	2465.27	1743
	2-B	4621	37.2	90.8	28.2	40.17	2737.55	14675
	5-B	4460	39.4	0.3	-3.2	-3.18	2899.45	-1097
	1-P	3569	51.5	8.1	1.8842	2.95	3789.89	778
Paper Products		30516	1985 Level					
and Allied	3,4-P	29173	4.4	14.4	1.5	3.39	1342.70	2527
Products	2-P	22673	25.7	104.4	32.1	45.84	7842.61	5845
	2-B	18371	39.8	565.5	165.4	239.72	12145.37	19738
	1-B	18828	38.3	16.6	5.4	7.59	11687.63	650
	1-P	17547	42.5	6.2	1.8681	2.68	12969.30	207
	5-B	16784	45.0	0.6	-8.3	-8.25	13732.20	-601
Metal		29480	1985 Level	-	-	-	-	-
Fabrication	1-B	26326	10.7	18.0	7.0	9.36	3154.35	2966
	2-B	26149	11.3	215.6	67.0	95.36	3331.23	28626
	5-B	25765	12.6	0.8	-6.1	-6.00	3714.47	-1615
	1-P	19663	33.3	41.6	10.2	15.71	9816.81	1601
Transportation		1801	1985 Level	-	-	-	-	-
Equipment	2-B	281	84.4	268.9	78.4	113.73	1520.04	74820
Industries	1-B	279	84.5	6.9	2.4	3.35	1521.85	2198
	5-B	11	99.4	0.3	-2.7	-2.62	1790.19	-1462

(*) CONTROL OPTIONS: 1) Lime Spray Dryer
2) Limestone Flue Gas Desulphurisation
3,4) Wet Processes - Caustic Absorption/Scrubbing
5) Fuel Switch to Natural Gas
B) Control on Boilers
P) Control on Process

TABLE 4-2 cont'd

SUMMARY OF SULPHUR DIOXIDE REDUCTION BY INDUSTRY CLASS

Source	Control Option (*)	SOI Emissions (Tonnes/year)	% Reduction	Capital Cost (million $)	Operating Cost (million $)	Total Annualized Cost (million $)	Amount of SO2 Removed (T/yr)	Annualized Costs per tonne SO2 Removed ($/tonne)
Non-Metallic		20248	1985 Level					
Mineral	1-B	19478	3.8	8.4	3.6	4.70	777.92	6038
Products	2-B	19397	4.2	187.8	56.6	81.33	843.00	96475
	5-B	19337	4.5	0.4	-1.8	-1.72	911.16	-1886
	1-P	4029	80.1	27.7	7.7	11.39	16218.57	702
Chemical &		69384	1985 Level					
Petroleum	1-P	53009	23.6	3.3	2.0	2.41	16374.62	147
Products	2-B	49887	28.1	209.1	65.2	92.69	19496.90	4754
	1-B	45238	34.8	30.4	10.7	14.65	24145.63	607
	5-B	41006	40.9	1.4	-36.2	-36.00	28378.06	-1269
	2-P	35108	49.4	246.9	79.0	111.42	34275.70	3251
Other		4805	1985 Level					
Groups	2-B	1552	67.7	750.4	226.2	324.86	3252.71	99873
	1-B	1158	75.9	40.9	17.2	22.59	3646.69	6196
	5-B	168	89.2	2.0	-1.9	-1.67	4285.70	-390

(*) CONTROL OPTIONS: 1) Lime Spray Dryer
2) Limestone Flue Gas Desulphurisation
3,4) Wet Processes - Caustic Absorption/Scrubbing
5) Fuel Switch to Natural Gas
B) Control on Boilers
P) Control on Process

TABLE 4-3

SUMMARY OF NITROGEN DIOXIDE REDUCTIONS
FOR MAJOR SOURCES

Source	Control Option (*)	NOx Emissions (,000T/yr.)	Overall % Reduction	Capital Cost (Million $)	Operating Cost (Million $)	Annualised Cost (Million $)	Amount of NOx Removed (,000 T/yr)	Annualised Cost/Tonne NOx Removed ($/Tonne)	Annual Production Capacity
Ontario Hydro		61.33	Base Case (1994)						99.4 million MWE at rated capacity (SENES, 1988)
	4	55.197	10%	13.0	2.50	4.21	6.13	687	
	4	49.064	20%	26.1	5.00	8.43	12.27	687	
	4	42.931	30%	39.1	7.50	12.64	18.40	687	
	4	30.665	50%	65.1	12.50	21.05	30.67	687	
	4	24.900	59.4%	77.1	14.90	24.99	36.43	687	

(*) CONTROL OPTION 1) Low Excess Air
2) Staged Combustion
3) Selective Non-Catalytic Reduction
4) Selective Catalytic Reduction

NOTE: Option 4 applied to units as needed to achieve each stage of reduction

TABLE 4-4

SUMMARY OF NITROGEN DIOXIDE REDUCTIONS BY INDUSTRY CLASS

Source	Control Option (*)	NOx Emissions (Tonnes/year)	Overall % Reduction	Capital Cost (million $)	Operating Cost (million $)	Annualized Cost (million $)	Amount of NOx Removed (T/yr)	Annualized Cost per tonne NOx Removed ($/tonne)
Food/Beverage		2873	1985 Level	-	-	-	-	-
	1	2729	5	0.6	-1.3	-1.2	144.21	-8471
	2	2585	10	3.9	0.8	1.3	288.14	4343
	3	1265	56	30.0	6.6	10.5	1607.62	6555
	4	595	79	137.1	24.1	42.1	2277.56	18496
Rubber &		386	1985 Level	-	-	-	-	-
Plastics	1	343	11	0.1	-0.4	-0.4	43.11	-10113
	2	300	22	0.7	0.1	0.2	86.25	2324
	3	154	60	4.0	0.9	1.4	231.54	6109
	4	58	85	18.9	3.3	5.8	328.02	17721
Textile		1180	1985 Level	-	-	-	-	-
	1	1058	10	0.1	-0.4	-0.4	121.65	-2912
	2	937	21	1.8	0.1	0.3	243.30	1299
	3	508	57	3.7	0.8	1.3	671.84	1926
	4	228	81	17.2	3.0	5.3	951.71	5552
Paper Products		11429	1985 Level	-	-	-	-	-
and Allied	1	10225	11	1.5	-2.8	-2.6	1203.44	-2179
Products	2	9021	21	5.0	2.0	2.6	2408.03	1075
	3	4682	59	88.4	19.4	31.0	6746.36	4601
	4	1871	84	413.5	72.7	127.1	9557.82	13297
Metal		14812	1985 Level	-	-	-	0.0	-
Fabrication	1	14207	4	1.9	-4.3	-4.0	605.83	-6669
	2	13602	8	8.3	1.3	2.3	1210.17	1898
	3	6328	57	76.5	16.8	26.9	8484.54	3156
	4	2792	81	273.4	48.1	84.0	12020.26	6990

(*) CONTROL OPTIONS
1) Low Excess Air
2) Staged Combustion
3) Selective Non-Catalytic Reduction
4) Selective Catalytic Reduction

TABLE 4-4 cont'd

SUMMARY OF NITROGEN DIOXIDE REDUCTIONS BY INDUSTRY CLASS

Industry Class	Control Option (*)	NOx Emissions (Tonnes/year)	Overall % Reduction	Capital Cost (million $)	Operating Cost (million $)	Annualized Cost (million $)	Amount of NOx Removed (T/yr)	Annualized Cost per tonne NOx Removed ($/tonne)
Transportation		2099	1985 Level	-	-	-	0.00	-
Equipment	1	1972	6	0.3	-2.4	-2.3	127.63	-18219
Industries	2	1844	12	9.0	0.7	1.8	255.26	6944
	3	860	59	13.9	3.1	4.9	1239.37	3944
	4	343	84	65.2	11.5	20.0	1755.77	11411
Non-Metallic		9826	1985 Level	-	-	-	0.00	-
Mineral	1	9406	4	0.8	-8.9	-8.8	420.57	-20985
Products	2	8986	9	3.1	2.5	2.9	840.16	3471
	3	4523	54	46.9	10.6	16.1	5303.31	3031
	4	2313	76	316.5	56.7	93.8	7513.27	12490
Chemical &		28587	1985 Level	-	-	-	0.00	-
Petroleum	1	27149	5	1.7	-17.6	-17.3	1437.90	-12061
Products	2	25708	10	8.6	5.0	6.0	2878.66	2085
	3	12958	55	95.3	20.9	33.5	15628.24	2141
	4	6446	77	437.7	77.0	134.5	22140.24	6076
Other		4298	1985 Level	-	-	-	0.00	-
Groups	1	3814	11	3.1	-5.4	-5.1	483.90	-10489
	2	3330	23	9.1	1.6	2.7	967.37	2749
	3	2285	47	65.8	14.4	23.1	2012.09	11481
	4	1447	66	196.6	35.6	61.4	2850.53	21551

(*) CONTROL OPTIONS
1) Low Excess Air
2) Staged Combustion
3) Selective Non-Catalytic Reduction
4) Selective Catalytic Reduction

4.2 Industrial Sectors

4.2.1 Industrial Sector Costs

For the purposes of this study specific control methods were applied to selected source types; these choices would not necessarily be those chosen by the companies should controls be imposed by regulatory action.

The technologies used for costing purposes are listed in Table 4.5 which also indicates their characteristics. The technologies imposed were those considered to be the most suitable for the types of process being assessed, based on the level of detail available from the inventory data. The costs are approximate estimates which can vary by a factor of two or more depending on the specific design needs, installation costs and operation mode.

Sulphur Dioxide Control

Sulphur dioxide control costs are summarized in Table 4.1 for the major point sources and Table 4.2 for the industrial sectors. The data from which these tables were derived are displayed in Appendix A. Table A-4.1 indicates the sources and the quantities of emission for each sector.

The types of industrial processes and the number of sources of each type are identified in Table A-4.3.0 while Tables A-4.4.2 to A-4.4.5 present the costs for control methods for the specific processes listed in Table A-4.3.0. These costs are summarized for all processes in Table A-4.4.1. Capital costs are listed in the top section of the tables and operating costs are in the lower section. The costs of applying selected technologies to boilers are shown similarly in Tables A-4.4.6 to A-4.4.8.

Tables, A-4.5.1 to A-4.5.6, present capital, operating and annualized costs, as well as the the quantities of SO_2 removed, removal efficiencies and the cost of removal per tonne for each sector. The overall summary of these

TABLE 4.5

CONTROL TECHNOLOGIES AND THEIR TECHNICAL CHARACTERISTICS

Technology	Controlled Compound	Control Location	Efficiency of Removal (%)	Estimated Lifetime (yrs)	Time to Install (yrs)
Selective Catalyic Reduction (SCR)	NO_x	stack	85	15	3
Selective Non-Catalytic Reduction (SNCR)	NO_x	process	60	15	2
Low Excess Air	NO_x	process	20	20	0.5
Staged Combustion	NO_x	process	40	20	1
Fuel Change (Oil to Gas)	SO_2	process	99.9	15	1
Lime Spray Dryer	SO_2	stack	85	15	2
Wet Scrubbing - Caustic Absorption	SO_2	stack	95	15	2.5
- Caustic Scrubbing	SO_2	stack	95	15	2.5
Limestone FGD	SO_2	stack	95	15	3

estimates is displayed in Table A-4.2 which also shows the costs for achieving various levels of control for each sector.

Nitrogen Oxide Control

The costs for controlling NO_x are summarized for major sources in Table 4.3 and for industrial sectors in Table 4.4. Tables A-4.7.1 to A-4.7.4 contain the costs for the control of processes and Tables A-4.7.5 to 8, the costs for boilers by four different methods: SCR, SNCR, combustion modifications and the use of a low excess air supply. The costs for each process and fuel type within each industrial sector are shown for the four methods and the total for each sector is given in the last column of these tables. The totals for each industry were then transferred to Tables A-4.8.1 to A-4.8.4, in which the annualized costs and the costs per tonne of NO_x removed are calculated, also shown are the total tonnes of NO_x removed and the efficiency of removal.

The most effective methods of control, as shown by the overall efficiencies of 78.7% (Table 4.8.4) and 55.5% (Table 4.8.3), are the SCR and SNCR processes, although the costs per tonne removed are higher than the costs for combustion modification and low excess air. These two emission reduction methods are, however applicable to a wider range of sources than the combustion control methods.

4.2.2 Petroleum Fuel Desulphurization.

The costs of fuel desulphurization vary with the method of obtaining the lower sulphur content fuels and the extent to which the desulphurization is carried out. The basis of the costs used in this study is the unpublished report by MHG International Ltd. (1983).

The MHG (1983) report considers six cases of sulphur reduction, which may briefly be described as:

Case 1. Sulphur in Light Fuel Oil (LFO) reduced to 0.3%.

Case 2. Sulphur in LFO reduced to 0.1%.

Case 3. Sulphur in LFO limited to 0.3%, with a reduction in the quantity of Heavy Fuel Oil (HFO) as 66% of the vacuum column bottom stream treated in an H-Oil unit to produce LFO.

Case 4. As Case 3. except that the LFO is limited to 0.1% sulphur.

Case 5. As Case 3. except that 90% of the vacuum bottoms are converted in the H-Oil unit.

Case 6. As Case 4. except that 90% of the vacuum bottoms are converted in the H-Oil unit.

Although the MHG study indicates that Case 1 can be met, under current refinery operating practices, it is noted that the refineries do produce distillate oil with sulphur content in excess of 0.3%. However, when it is necessary, for inventory purposes, to estimate SO_2 emission from other available data, MOE (telephone communication between S. Wong and B. Powers) in the past have assumed 0.3% sulphur content for distillate consuming boilers and heaters. For the purposes of the current study it has been assumed that the 0.3% sulphur content could be achieved with no extra capital expenditure, and Case 1 is therefore the base case. The costs of carrying out the other five cases are displayed at the bottom of Table 4.1. The lowest cost per tonne of SO_2 removed ($304.7) is a result of applying Case 2, but the reduction in emissions amounts to only 5% (10,040 T/yr). The major reduction of 20% of the total emissions would cost $510.1/tonne and remove 36,920 tonnes per year of emissions.

The overall reductions in the emissions by industry and from the refineries are shown in Table A-4.11 which, based on the process heat requirements, also shows how the fuels produced would be distributed between consumption in the

refinery itself and sales to consumers. The impact of these changes on the industrial sectors has been determined by ratioing the costs to the fraction of the total SO_2 emissions in the province which arise from the oil consuming processes and boilers in the specified sectors. The emission reduction resulting from use of the fuels by the industrial sectors, and the allocated costs are given in Table A-4.10 and A-4.11, respectively. The costs per tonne SO_2 removed are listed in Table A-4.12.

4.3 Major Point Sources

4.3.1 Falconbridge

The costs of controlling emissions from the major point sources are summarized in Tables 4.1 and 4.3.

Sulphur Dioxide Control

The estimates are based on the decision that reductions should be achieved by the use of dry lime scrubbing on all or part of the remaining emissions. The sources, residual emissions from processes, contain over 2% SO_2 and therefore do not require wet processes to ensure high removal efficiency. The use of wet scrubbing technologies are more costly unless recovery of the sulphur values is practicable. At the low SO_2 concentrations the cost of recoveries generally will outweigh the value of the product. The wet processes have therefore not been costed for Falconbridge.

Annualized costs for these additional controls range from $11.6 million for a reduction of 10% to $78.3 million for a 50% reduction in emissions. These costs are mainly due to operating the control equipment. Because of the low quantities of emissions being controlled the costs per tonne of SO_2 range from $1160 to $1566.

4.3.2 INCO

Sulphur Dioxide Control

Since the requirement in this case is to control relatively weak tail gases from the acid plants and from high flow fugitive emissions it has been assumed that wet limestone scrubbing is the preferred control technology. This method is capable of up to 95% recovery efficiency. Costs per tonne of pollutant removed varies with the concentration of the source gases and the gas flow rate. The capital, operating and annualized costs for specific reduction amounts are presented in Table A.4.1. Annualized costs for these additional controls range from $20 million for a reduction of 10% to $48 million for a 50% reduction in emissions. About 70% of these costs are for operating the control equipment. Because of the quantities of emissions being controlled the costs per tonne of SO_2 range from $752 to $362.

4.3.3 Algoma

Sulphur Dioxide Control

Reductions in SO_2 emissions of up to 20% at Wawa could be obtained by ore beneficiation. Based on cost estimates of coal cleaning and making allowance for the size of the operation and the extent of ore cleaning required to produce a 10% reduction it is estimated that capital costs of $13,400,000 and operating costs of $90,000 would be required and result in annualized costs of $1,660,000 and a cost of $133/tonne removed.

For a reduction of 20% the capital expenditure would need to be raised to $22,500,000 and operating expenses would increase to $111,000 per year. The cost per tonne removed would be $110.

Further reductions would need to be made by the use of flue gas cleaning. It would be necessary to scrub one half of the exhaust gases from the sinter strands in order to carry out an effective reduction program rather than scrub

all of the stream to a lower efficiency. This procedure was estimated to require $21,940,000 of capital with operating costs of $35,600,000 for an annualized cost of $38,140,000. It would remove 37,500 tonnes at a cost of $1,020 per tonne. A 50% reduction would result in operating costs of $48,000,000 and a capital expenditure of $27,200,000 for an annualized cost of $51,200,000 and remove 61,250 tonnes a year at a cost of $835.8 per tonne of SO_2.

Nitrogen Oxide Control

This operation is not a major source of NO_x emissions and the sintering process is not readily amenable for NO_x control.

4.3.4 Ontario Hydro

Sulphur Dioxide Control

Ontario Hydro has carried out detailed studies on the use of limestone scrubbing for the control of its acid gas emissions. The costs developed have been used in these estimates after comparison with estimates made by MOE and others who have indicated that they are acceptable for this purpose.

In order to meet the requirements of the Ontario Regulation 281/87 a capital expenditure of $560,000,000 will be required. With operating costs of $42,000,000 per year this results in annualized costs of $133,000,000.

As shown in Table 4.1, further reductions of up to 50% require capital expenditures of 62.3 to 311.5 million dollars, and annualized costs of 14.8 to 74.1 million dollars. The costs per tonne of SO_2 removed range from $845 to $848, compared with $573 per tonne for the initial approach to the target emission level. Although it was assumed that further reductions would be achieved by the installation of a similar technology, the variations arise from the overall size of the installations and the number and size of the scrubbing units required in the different circumstances.

Nitrogen Oxide Control

Costs for the control of nitrogen oxides at Ontario Hydro have been based on the costs of controls, using Selective Catalytic Reduction at generating stations in the United States. The effectiveness of SCR is such that it permits the required overall removal efficiencies with the least number of installations.

Costs have been developed for this study based on the data for 36 generating stations in the U.S.A., with overall collection efficiencies ranging from 8 t0 40 % (Calvert and Englund, 1984).

From the list the fourteen stations which reduced emissions by 40% were selected and the average costs for these stations were developed. The average capital costs amounted to $856.2 (US, 1980)/ton removed, this equates to $1442/tonne removed (Cdn.1986) for a plant which has no controls installed. The annual operating costs were equivalent to $215 (Cdn. 1986) tonne removed.

These costs appear to be low when compared with costs developed by many authors, for specific generating stations or for a detailed but generalised design of station. However it was felt that the actual experience of a number of stations would be the most suitable for use in this current study where the explicit details of designs could not be developed in the absence of details about the existing state of controls at any one station.

The emissions from the Ontario Hydro stations will have been reduced from 94,400 tonnes/year (current conditions) to 61,330 tonnes/year in 1994 (Base case). At that emission rate capital costs are estimated to be $13,000,000 or $1337/tonne for the removal of 10% of the emissions while annual operating costs, after making an allowance for increased Canadian labour and materials costs would be $2,500,000. The annualised cost then becomes $4,210,000/year based on a 25 year plant life and 12.5% interest on capital for a cost of $687./tonne NO_x removed.

It has been assumed that further reductions will be achieved by the installation of modular units of equal size and the costs per tonne of removal will be constant. Capital costs will then range from $13,000,000 for a 10% reduction in emissions from 61,330 tonnes/year to 55,197 tonnes/yr. Operating costs will amount to $2,500,000/year and the annualised costs will be $4,210,000/year. For each additional reduction of 6,133 tonnes costs will increase proportionately until at a reduction of 59.4%, the annualised costs will amount to $77,100,000/year (Table 4-3)

The use of combustion modifications has not been addressed in this study. The experimental work at Nanticoke has indicated that NO_x reduction of up to 60% may be achievable, however results have not been fully assessed and published. The technologies covered are dependent on the boiler design and are unlikely to be applicable to the same degree at other stations. Further confirmation of the effectiveness and the cost is desirable before these modifications can be considered in this study for the large Ontario Hydro boilers.

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APPENDIX A

COST ESTIMATES

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A-4.2 Nitrogen Dioxide Emissions - 1985 Level

A-4.3.0 Process Identification for Sulphur Dioxide Sources

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A-4.4.2 SO_2 Reduction Costs for Process Streams - Lime Spray Dryer

A-4.4.3 SO_2 Reduction Costs for Process Streams - Limestone FGD

A-4.4.4 SO_2 Reduction Costs for Process Streams - Caustic Absorption

A-4.4.5 SO_2 Reduction Costs for Process Streams - Caustic Scrubbing

A-4.4.6 SO_2 Reduction Costs for Boilers - Lime Spray Dryer

A-4.4.7 SO_2 Reduction Costs for Boilers - Limestone FGD

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A-4.5.1 SO_2 Removal Costs for Boilers - Lime Spray Dryer

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A-4.5.3 SO_2 Removal Costs for Boilers - Fuel Switch to Natural Gas

A-4.5.4 SO_2 Removal Costs for Process Streams - Lime Spray Dryer

A-4.5.5 SO_2 Removal Costs for Process Stream - Limestone FGD

A-4.5.6 SO_2 Removal Costs for Process Stream - Wet Scrubbing

A-4.6.0 Identification for NO_x Process Streams

A-4.7.1 NO_x Reduction Costs for Process Streams - Low Excess Air

A-4.7.2 NO_x Reduction Costs for Process Streams - Staged Combustion

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A-4.10 Costs of Fuel Oil Desulphurization
A-4.11 Estimated Overall Emissions Reduction of SO_2 From Fuel Usage
A-4.12 Per Tonne Cost of Fuel Oil Desulphurization

TABLE A-4.1

SULPHUR DIOXIDE EMISSIONS-1985 Level

Industry	Sulphur dioxide emissions (T/year) Exclusive of Natural Gas								
	Process Emissions	% of Total	Boiler Emissions				Total Boilers	% of Total
			Distillate	Residual	Coal	Other *		
Primary Metals	14209.5	13.81	9.7	0.0	0.0	0.0	9.7	0.01
Food & Beverage	353.6	0.34	171.4	895.6	0.0	0.0	1067.0	1.40
Textile Industries	4454.5	4.33	20.8	2882.7	0.0	0.0	2903.5	3.80
Paper & Allied Products	16201.1	15.75	992.7	2836.2	10450.1	36.0	14315.0	18.75
Metal Fabricating	11864.9	11.53	239.3	3161.8	0.0	14213.9	17615.0	23.07
Transportation Equipment	5.4	0.01	194.7	787.9	812.5	0.0	1795.1	2.35
Non-metallic Products	19308.3	18.77	51.0	828.3	60.3	0.0	939.6	1.23
Chem. & Chem. Products	36073.3	35.07	12760.9	15877.1	0.0	4672.9	33310.9	43.63
Other Major Groups	404.3	0.39	936.8	3195.6	267.9	0.0	4400.3	5.76
TOTALS	102874.9	100.00	15377.3	30465.2	11590.8	18922.8	76356.1	100.00
% of overall TOTALS	57.40		8.58	17.00	6.47	10.56	42.60	
						Total emissions:-	179231.00	100.00

* Note :- "Other" includes products used as fuels e.g. Coke oven gas and Sulphur Plant tail gas listed as "Fuels" in the inventory.

TABLE A-4.2

NITROGEN DIOXIDE EMISSIONS (T/year)- 1985 LEVELS

Industry	NITROGEN DIOXIDE EMISSIONS (T/year).									
	Process Emissions	% of Total	Boiler Emissions					Total Boilers	% of Total
			Nat. Gas	Distillate	Residual	Coal	Other *		
Food & Beverage	54.9	0.16	1684.4	269.9	542.9	0.0	320.6	2817.9	6.68
Rubber & Plastics	0.0	0.00	170.3	36.2	179.4	0.0	0.0	385.9	0.92
Textile Industries	497.1	1.49	58.2	7.5	617.2	0.0	0.0	682.8	1.62
Paper & Allied Products	5508.4	16.53	2005.5	281.7	488.8	2272.1	872.2	5920.3	14.04
Metal Fabricating	4580.9	13.75	1163.2	160.9	1507.3	0.0	7400.1	10231.5	24.26
Transportation Equipment	0.0	0.00	923.0	425.7	222.9	527.6	0.0	2099.2	4.98
Non-metallic Products	8761.4	26.29	758.5	43.5	218.2	11.9	32.9	1065.0	2.53
Chem. & Chem. Products	13283.2	39.87	4215.9	1550.7	4015.2	0.0	5521.7	15303.5	36.29
Other Major Groups	634.2	1.90	1660.6	493.2	1377.6	33.5	98.5	3663.3	8.69
TOTALS	33320.1	100.00	12639.6	3269.3	9169.5	2845.1	14246.0	42169.4	100.00
% of overall TOTALS		44.14	16.74	4.33	12.15	3.77	18.87	55.86	
							Total emissions:-	75489.47	100.00

* Note :- "Other" includes products used as fuels e.g. Coke oven gas and Sulphur Plant tail gas listed as "Fuels" in the inventory.

TABLE A-4.3.0

PROCESS IDENTIFICATION FOR SULPHUR DIOXIDE SOURCES

	Process	# of Sources	Process	# of Sources	Process	# of Sources	Process	# of Sources	Process	# of Sources	Process	# Sources
Primary Metals	Melt. Smelt	4										
Food & Beverage	Barley. Prod	1										
Textile Industries	Misc.	2										
Paper & Allied Products	Absorp. Tower	16	Black Liquor	4	Misc.	7	Rec. Boilers	11	Lime Kiln	9	Smelt Kiln	4
Metal Fabricating	CO Gas	11	BF Gas	8	Resid Oil	3	Lime Kiln	4				
Transportation Equipment												
Non-metallic Products	Coal Kiln	5	Kiln- General	7	Glass, Dist oil	2	Glass- N. Gas	2				
Chem. & Chem. Products	Crude Ref.	16	Process Gas	17								
Other Major Groups ‡	Incinerators	8										

‡ Total SO2 Sources From Industrial Processes =138

‡ All other sources in group were less than 10 tonnes/year and therefore were omitted from the study

TABLE A-4.4.1

SO2 REDUCTION COSTS FOR PROCESS STREAMS

Control Process :- SUMMARY OF ALL CONTROL STRATEGIES
(AS LISTED IN TABLES A-4.4.2 TO A-4.4.5)

CAPITAL COSTS ($) :- Processes

Industry	Process #1	Control Code *	Process #2	Control Code	Process #3	Control Code	Process #4	Control Code	Process #5	Control Code	Process #6	Control Code	Total Cap.Cost
Primary Metals	2093708	2											2093708
Food & Beverage	440511	1											440511
Textile Industries	8080494	1											8080494
Paper & Allied Products	12364800	4	21075808	2	6240465	1	69015958	2	1416339	3	586844	3	110700214
Metal Fabricating	21281931	1	11618896	1	415035	1	8243576	1					41559438
Transportation Equipment													
Non-metallic Products	8093180	1	15877365	1	2188572	1	1502490	1					27661607
Chem. & Chem. Products	142224128	2	92682928	2									236907057
Other Major Groups	3265217	1											3265217
												Total	430708246

OPERATING COSTS ($) :- Processes

Industry	Process #1	Control Code	Process #2	Control Code	Process #3	Control Code	Process #4	Control Code	Process #5	Control Code	Process #6	Control Code	Total Op. Cost
Primary Metals	7196207	2											7196207
Food & Beverage	225872	1											225872
Textile Industries	1884206	1											1884206
Paper & Allied Products	704000	4	7240500	2	1868090	1	23438008	2	578853	3	249960	3	34079411
Metal Fabricating	4615171	1	2734144	1	1120035	1	1775784	1					10245134
Transportation Equipment													
Non-metallic Products	2333935	1	4246725	1	617972	1	550842	1					7749474
Chem. & Chem. Products	46796880	2	32157285	2									78954178
Other Major Groups	1979005	1											1979005
												Total	142313487

* Control Codes:
1) Lime Spray Drying
2) Limestone FGD
3) Caustic Absorption
4) Caustic Scrubbing

TABLE A-4.4.2

SO2 REDUCTION COSTS FOR PROCESS STREAMS Control Process :- LIME SPRAY DRYER (CODE #1)

CAPITAL COSTS ($) :- Processes

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Total Cap.Cost
Primary Metals		4											
Food & Beverage	440511	1											440511
Textile Industries	4040247	2											8080494
Paper & Allied Products		16		4	891495	7		11		9		4	6240465
Metal Fabricating	1934721	11	1452362	8	138345	3	2060894	4					41559438
Transportation Equipment													
Non-metallic Products	1618636	5	2268195	7	1094286	2	751245	2					27661603
Chem. & Chem. Products		16		17									
Other Major Groups	408152	8											3265217
												Total:-	87247728

OPERATING COSTS ($) :- Processes

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Total Op. Cost
Primary Metals		4											
Food & Beverage	225872	1											225872
Textile Industries	942103	2											1884206
Paper & Allied Products		16		4	266870	7		11		9		4	1868088
Metal Fabricating	419561	11	341768	8	373345	3	443946	4					10245131
Transportation Equipment													
Non-metallic Products	466787	5	606675	7	308986	2	275421	2					7749474
Chem. & Chem. Products		16		17									
Other Major Groups	247376	8											1979005
												Total:-	23951777

TABLE A-4.4.3

SO2 REDUCTION COSTS FOR PROCESS STREAMS Control Process :- LIMESTONE FLUE GAS DESULPHURIZATION (Code #2)

CAPITAL COSTS ($) :- Processes

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Total Cap.Cost
Primary Metals	523427	4											2093708
Food & Beverage		1											0
Textile Industries		2											0
Paper & Allied Products		16	5268952	4		7	6274178	11		9		4	90091764
Metal Fabricating		11		8		3		4					0
Transportation Equipment													0
Non-metallic Products		5		7		2		2					0
Chem. & Chem. Products	8889008	16	5569584	17									236907057
Other Major Groups		8											0
											Total:-		329092529

OPERATING COSTS ($) :- Processes

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Total Op. Cost
Primary Metals	1799052	4											7196207
Food & Beverage		1											
Textile Industries		2											
Paper & Allied Products		16	1810125	4		7	2130728	11		9		4	30678504
Metal Fabricating		11		8		3		4					
Transportation Equipment													
Non-metallic Products		5		7		2		2					
Chem. & Chem. Products	2924805	16	1891605	17									78954178
Other Major Groups		8											
											Total:-		116828889

TABLE A-4.4.4

SO2 REDUCTION COSTS FOR PROCESS STREAMS Control Process :- CAUSTIC ABSORPTION (Code #3)

CAPITAL COSTS ($):- Processes

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Total Cap.Cost
Primary Metals		4											
Food & Beverage		1											
Textile Industries		2											
Paper & Allied Products		16		4		7		11	157371	9	146711	4	2003184
Metal Fabricating		11		8		3		4					
Transportation Equipment													
Non-metallic Products		5		7		2		2					
Chem. & Chem. Products		16		17									
Other Major Groups		8											
											Total:-		2003184

OPERATING COSTS ($):- Processes

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Total Op. Cost
Primary Metals		4											
Food & Beverage		1											
Textile Industries		2											
Paper & Allied Products		16		4		7		11	64317	9	62490	4	828815
Metal Fabricating		11		8		3		4					
Transportation Equipment													
Non-metallic Products		5		7		2		2					
Chem. & Chem. Products		16		17									
Other Major Groups		8											
											Total:-		828815

TABLE A-4.4.5

SO2 REDUCTION COSTS FOR PROCESS STREAMS Control Process :- CAUSTIC SCRUBBING (Code #4)

CAPITAL COSTS ($) :- Processes

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Total Cap.Cost
Primary Metals		4											
Food & Beverage		1											
Textile Industries		2											
Paper & Allied Products	772800	16		4		7		11		9		4	12364800
Metal Fabricating *		11		8		3		4					
Transportation Equipment													
Non-metallic Products		5		7		2		2					
Chem. & Chem. Products *		16		17									
Other Major Groups		8											
											Total:-		12364800

OPERATING COSTS ($) :- Processes

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Total Op. Cost
Primary Metals		4											
Food & Beverage		1											
Textile Industries		2											
Paper & Allied Products	44000	16		4		7		11		9		4	704000
Metal Fabricating *		11		8		3		4					
Transportation Equipment													
Non-metallic Products		5		7		2		2					
Chem. & Chem. Products *		16		17									
Other Major Groups		8											
											Total:-		704000

TABLE A-4.4.6

SOx REDUCTION COSTS for BOILERS Control process - LIME SPRAY DRYER (Code #1)

CAPITAL COSTS ($) :- Boilers

Industry Sector	Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	Total Cap.Cost
Primary Metals											
Food & Beverage		1	555825	4	539429	18					11933019
Textile Industries			452651	1	873792	10					9190566
Paper & Allied Products			873936	4	689178	9	1147667	6			16584348
Metal Fabricating		1	528281	4	661430	24				12	17987446
Transportation Equipment			535722	3	811430	3	949929	3			6891240
Non-metallic Products			409418	2	587750	12	528524	1			8400357
Chem. & Chem. Products		2	686241	18	819257	22				1	30375983
Other Major Groups		1	541229	20	585408	48	502551	4			40934353
										Total	142297313

OPERATING COSTS ($) :- Boilers

Industry Sector	Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	Total Op. Cost
Primary Metals											
Food & Beverage		1	233365.7	4	236972.7	18					5198971
Textile Industries			224865.2	1	286276.6	10					3087631
Paper & Allied Products			271406.8	4	256703.7	9	335494.5	6			5408928
Metal Fabricating		1	231013.2	4	252740.2	24				12	6989818
Transportation Equipment			239793.6	3	275698.5	3	297360.2	3			2438557
Non-metallic Products			221567.4	2	242892.2	12	235226.6	1			3593068
Chem. & Chem. Products		2	253150.7	18	276996.2	22				1	10650629
Other Major Groups		1	232110.9	20	242599.2	48	232349.1	4			17216376
										Total	54583977

TABLE A-4.4.7

SOx REDUCTION COSTS for BOILERS Control Process:- LIMESTONE FLUE GAS DESULFURIZATION (Code 82)

CAPITAL COSTS ($) :- Boilers

Industry Sector	Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	Total Cap.Cost
Primary Metals											
Food & Beverage			1	4	8958662	18					161255912
Textile Industries				1	9082029	10					90820290
Paper & Allied Products				4	8995554	9	80760575	6			565523439
Metal Fabricating			1	4	8984606	24				12	215630548
Transportation Equipment				3	9050053	3	80593666	3			268931156
Non-metallic Products				2	8958013	12	80363722	1			187859874
Chem. & Chem. Products			2	18	9053922	22			8270633	1	207456922
Other Major Groups			1	20	8938220	48	80333609	4			750368980
									Total		2447847122

OPERATING COSTS ($) :- Boilers

Industry Sector	Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	Total Op. Cost
Primary Metals											
Food & Beverage			1	4	2783090.4	18					50095627
Textile Industries				1	2823712.0	10					28237120
Paper & Allied Products				4	2795801.0	9	23368916.0	6			165375705
Metal Fabricating			1	4	2792268.1	24				12	67014434
Transportation Equipment				3	2813390.0	3	23311914.0	3			78375912
Non-metallic Products				2	2783685.0	12	23233041.0	1			56637261
Chem. & Chem. Products			2	18	2814639.6	22			3247054.0	1	65169125
Other Major Groups			1	20	2777268.5	48	23223107.0	4			226201316
									Total		737106501

TABLE A-4.4.8

SOx REDUCTION COSTS for BOILERS Control process - FUEL CHANGE TO NATURAL GAS (Code #5)

CAPITAL COSTS ($) :- Boilers

Industry Sector	Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	Total Cap.Cost
Primary Metals											
Food & Beverage		1	33560	4	25597	18					594979
Textile Industries			29695	1	27524	10					304930
Paper & Allied Products			54938	4	26316	9	29381	6			632879
Metal Fabricating		1	32435	4	26161	24				12	757597
Transportation Equipment			36792	3	27084	3	27809	3			275056
Non-metallic Products			28364	2	25785	12	25461	1			391608
Chem. & Chem. Products		2	44061	18	27131	22				1	1389969
Other Major Groups		1	32952	20	25773	48	25365	4			1997604
										Total	6344622

OPERATING COSTS ($) :- Boilers (*)

Industry Sector	Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	Total Op. Cost
Primary Metals											
Food & Beverage		1	-783040	4	-80546	18					-4581987
Textile Industries			-438630	1	-278118	10					-3219809
Paper & Allied Products			-2688122	4	-156036	9	637643	6			-8330951
Metal Fabricating		1	-682773	4	-140323	24				12	-6098852
Transportation Equipment			-1071111	3	-233692	3	420152	3			-2653950
Non-metallic Products			-319901	2	-102398	12	95153	1			-1773425
Chem. & Chem. Products		2	-1718870	18	-236387	22				1	-36184175
Other Major Groups		1	-728928	20	-101134	48	24012	4			-19336924
										Total	-82180074

(*) NOTE: NEGATIVE COSTS INDICATE FUEL COST SAVINGS

TABLE A-4.5.1

SULPHUR DIOXIDE REMOVAL COSTS for BOILERS Control Method:- LIME SPRAY DRYER (Code #1)

Industry	Sulphur Dioxide Emissions(tonnes/yr) (Exclusive of Natural Gas)				Control Costs: $1987 (Cdn)								
	Process Emissions	% of Total	Total Boilers	% of Total	Capital $Cdn	Operating $Cdn	Annual $Cdn	Plant Life	Tonnes controlled	Control Eff'y %	Tonnes Removed	Cost/tonne $Cdn	Overall Eff'y
Primary Metals	14209.5	13.81	9.7	0.01									
Food & Beverage	353.6	0.34	1067.0	1.40	11933019	5198971	6767850	15	1000.5	85.00%	850.4	7958.2	59.9%
Textile Industries	4454.5	4.33	2903.5	3.80	9190566	3087631	4295949	15	2901.5	85.00%	2466.2	1741.9	33.5%
Paper & Allied Products	16201.1	15.75	14315.0	18.75	16584348	5408927	7589334	15	13737.5	85.00%	11676.9	649.9	38.3%
Metal Fabricating	11864.9	11.53	17615.0	23.07	17987446	6989818	9354695	15	3708.5	85.00%	3152.2	2967.6	10.7%
Transportation Equipment	5.4	0.01	1795.1	2.35	6891240	2438557	3344574	15	1790.6	85.00%	1522.0	2197.5	84.5%
Non-metallic Products	19308.3	18.77	939.6	1.23	8400358	3593068	4697495	15	915.2	85.00%	777.9	6038.5	3.8%
Chem. & Chem. Products	36073.3	35.07	33310.9	43.63	30375983	10650629	14644274	15	28398.3	85.00%	24138.6	606.7	34.8%
Other Major Groups	404.3	0.39	4400.3	5.76	40934353	17216377	22598171	15	4289.0	85.00%	3645.7	6198.7	75.9%
TOTALS	102874.9	100.00	76356.1	100.00	142297312	54583977	73292342		56741.0		48229.9	1519.6	26.9%
% of overall TOTALS	57.40		42.6						% of to SO2 emissions controlled				31.7%
	Total emissions:-		179231.0	100.00					% of total SO2 emissions removed				26.9%

TABLE A-4.5.2

SULPHUR DIOXIDE REMOVAL COSTS for BOILERS Control Method:- LIMESTONE FLUE GAS DESULPHURISATION (Code # 2)

Industry	Sulphur Dioxide Emissions(tonnes/yr) (Exclusive of Natural Gas)				Control Costs: $1987 (Cdn)								
	Process Emissions	% of Total	Total Boilers	% of Total	Capital $Cdn	Operating $Cdn	Annual $Cdn	Plant Life	Tonnes controlled	Control Eff'y %	Tonnes Removed	Cost/tonne $Cdn	Overall Eff'y
Primary Metals	14209.5	13.81	9.7	0.01									
Food & Beverage	353.6	0.34	1067.0	1.40	161255912	50095627	71296551	15	849.2	95.00%	806.7	88376.1	56.8%
Textile Industries	4454.5	4.33	2903.5	3.80	90822450	28237120	40177891	15	2882.7	95.00%	2738.6	14671.1	37.2%
Paper & Allied Products	16201.1	15.75	14315.0	18.75	565523440	165375705	239727208	15	12772.5	95.00%	12133.9	19756.9	39.8%
Metal Fabricating	11864.9	11.53	17615.0	23.07	215630548	67014434	95364197	15	3504.0	95.00%	3328.8	28648.2	11.3%
Transportation Equipment	5.4	0.01	1795.1	2.35	268931156	78375912	113733307	15	1600.0	95.00%	1520.0	74824.5	84.4%
Non-metallic Products	19308.3	18.77	939.6	1.23	187859874	56637261	81335908	15	887.4	95.00%	843.0	96480.4	4.2%
Chem. & Chem. Products	36073.3	35.07	33310.9	43.63	209111048	65169125	92661744	15	20533.7	95.00%	19507.0	4750.2	28.1%
Other Major Groups	404.3	0.39	4400.3	5.76	750368980	226201316	324855160	15	3423.9	95.00%	3252.7	99872.3	67.7%
TOTALS	102874.9	100.00	76356.1	100.00	2449503408	737106500	1059151965		46453.4		44130.7	24000.3	24.6%
% of overall TOTALS		57.40		42.6			% of total SO2 emissions controlled -						25.9%
	Total emissions:-		179231.0	100.00			% of total SO2 emissions removed -						24.6%

TABLE A-4.5.3

SULPHUR DIOXIDE REMOVAL COSTS for BOILERS Control Method:- FUEL SWITCH TO NATURAL GAS (Code # 5)

	Sulphur Dioxide Emissions(tonnes/yr) (Exclusive of Natural Gas)				Control Costs: $1987 (Cdn)								
Industry	Process Emissions	% of Total	Total Boilers	% of Total	Capital $Cdn	Operating $Cdn	Annual $Cdn	Plant Life	Tonnes controlled	Control Eff'y %	Tonnes Removed	Cost/tonne $Cdn	Overall Eff'y
Primary Metals	14209.5	13.81	9.7	0.01									
Food & Beverage	353.6	0.34	1067.0	1.40	594979	-4581988	-4503764	15	1000.5	99.90%	999.5	-4506.0	70.4%
Textile Industries	4454.5	4.33	2903.5	3.80	304930	-3219309	-3179219	15	2901.5	99.90%	2898.5	-1096.8	39.4%
Paper & Allied Products	16201.1	15.75	14315.0	18.75	632873	-8330951	-8247744	15	13737.5	99.90%	13723.8	-601.0	45.0%
Metal Fabricating	11864.9	11.53	17615.0	23.07	757597	-6098833	-5999229	15	3708.5	99.90%	3704.8	-1619.3	12.6%
Transportation Equipment	5.4	0.01	1795.1	2.35	275056	-2653950	-2617787	15	1790.6	99.90%	1788.8	-1463.4	99.4%
Non-metallic Products	19308.3	18.77	939.6	1.23	391608	-1773425	-1721939	15	915.2	99.90%	914.3	-1883.4	4.5%
Chem. & Chem. Products	36073.3	35.07	33310.9	43.63	1389969	-36184174	-36001430	15	28398.3	99.90%	28369.9	-1269.0	40.9%
Other Major Groups	404.3	0.39	4400.3	5.76	1997604	-19336924	-19074291	15	4289.0	99.90%	4284.7	-4451.7	89.2%
TOTALS	102874.9	100.00	76356.1	100.00	6344622	-82179554	-81345403		56741.0		56684.3	-1435.1	31.6%
% of overall TOTALS		57.40		42.6			% of total SO2 emissions controlled -						31.7%
	Total emissions:-		179231.0	100.00			% of total SO2 emissions removed -						31.6%

TABLE A-4.5.4

SULPHUR DIOXIDE REMOVAL COSTS for PROCESS STREAMS Control Method LIME SPRAY DRYER (Code # 1)

Industry	Sulphur Dioxide Emissions(tonnes/yr) (Exclusive of Natural Gas)				Control Costs: $1987 (Cdn)								
	Process Emissions	% of Total	Total Boilers	% of Total	Capital $Cdn	Operating $Cdn	Annual $Cdn	Plant Life	Tonnes controlled	Control Eff'y %	Tonnes Removed	Cost/tonne $Cdn	Overall Eff'y
Primary Metals	14209.5	13.81	9.7	0.01									
Food & Beverage	353.6	0.34	1067.0	1.40	440510	225872	283788	15	23.6	85.00%	20.1	14146.9	1.4%
Textile Industries	4454.5	4.33	2903.5	3.80	3080494	1884206	2946579	15	4454.5	85.00%	3786.3	778.2	51.5%
Paper & Allied Products	16201.1	15.75	14315.0	18.75	6240466	1863088	2683546	15	15249.0	85.00%	12961.7	207.0	42.5%
Metal Fabricating	11864.9	11.53	17615.0	23.07	41559438	10245131	15709107	15	11554.2	85.00%	9821.1	1599.5	33.3%
Transportation Equipment	5.4	0.01	1795.1	2.35				15				0.0	0.0%
Non-metallic Products	19308.3	18.77	939.6	1.23	27661603	7749474	11386249	15	19071.5	85.00%	16210.8	702.4	80.1%
Chem. & Chem. Products	36073.3	35.07	33310.9	43.63	3265217	1979005	2408295	15	19256.9	85.00%	16368.4	147.1	23.6%
Other Major Groups	404.3	0.39	4400.3	5.76				15					0.0%
TOTALS	102874.9	100.00	76356.1	100.00	87247728	23946776	35417564		69609.7		59168.2	598.6	33.0%
% of overall TOTALS		57.40		42.6					% of total SO2 emissions controlled -				38.8%
	Total emissions:-		179231.0	100.00					% of total SO2 emissions removed -				33.0%

TABLE A-4.5.5

SULPHUR DIOXIDE REMOVAL COSTS for PROCESS STREAMS Control Method LIMESTONE FGD (Code #2)

Industry	Sulphur Dioxide Emissions(tonnes/yr) (Exclusive of Natural Gas)				Control Costs: $1987 (Cdn)								
	Process Emissions	% of Total	Total Boilers	% of Total	Capital $Cdn	Operating $Cdn	Annual $Cdn	Plant Life	Tonnes controlled	Control Eff'y %	Tonnes Removed	Cost/tonne $Cdn	Overall Eff'y
Primary Metals	14209.5	13.81	9.7	0.01	2093708	7196207	7471474	15	14209.5	95.00%	13499.0	553.5	94.9%
Food & Beverage	353.6	0.34	1067.0	1.40									
Textile Industries	4454.5	4.33	2903.5	3.80									
Paper & Allied Products	16201.1	15.75	14315.0	18.75	90091764	30678504	42523208	15	7401.6	95.00%	7031.5	6047.5	23.0%
Metal Fabricating	11864.9	11.53	17615.0	23.07									
Transportation Equipment	5.4	0.01	1795.1	2.35									
Non-metallic Products	19308.3	18.77	939.6	1.23									
Chem. & Chem. Products	36073.3	35.07	33310.9	43.63	236907056	78954178	110101243	15	36051.7	95.00%	34249.1	3214.7	49.4%
Other Major Groups	404.3	0.39	4400.3	5.76									
TOTALS	102874.9	100.00	76356.1	100.00	329092528	116828889	160095926		57662.8		54779.7	2922.5	30.6%
% of overall TOTALS		57.40		42.6				% of total Boiler emissions controlled -					32.2%
	Total emissions:-		179231.0	100.00				% of total Boiler emissions removed -					30.6%

TABLE A-4.5.6

SULPHUR DIOXIDE REMOVAL COSTS for PROCESS STREAMS Control Method WET SCRUBBING (Codes # 3 & 4)

Industry	Sulphur Dioxide Emissions(tonnes/yr) (Exclusive of Natural Gas)				Control Costs: $1987 (Cdn)								
	Process Emissions	% of Total	Total Boilers	% of Total	Capital $Cdn	Operating $Cdn	Annual $Cdn	Plant Life	Tonnes controlled	Control Eff'y %	Tonnes Removed	Cost/tonne $Cdn	Overall Eff'y
Primary Metals	14209.5	13.81	9.7	0.01									
Food & Beverage	353.6	0.34	1067.0	1.40									
Textile Industries	4454.5	4.33	2903.5	3.80									
Paper & Allied Products	16201.1	15.75	14315.0	18.75	14367984	1532815	3421828	15	7474.7	95.00%	7101.0	481.9	23.3%
Metal Fabricating	11864.9	11.53	17615.0	23.07									
Transportation Equipment	5.4	0.01	1795.1	2.35									
Non-metallic Products	19308.3	18.77	939.6	1.23									
Chem. & Chem. Products	36073.3	35.07	33310.9	43.63									
Other Major Groups	404.3	0.39	4400.3	5.76									
TOTALS	102874.9	100.00	76356.1	100.00	14367984	1532815	3421828		7474.7		7101.0	481.9	4.0%
% of overall TOTALS		57.40		42.6				% of total Boiler emissions controlled -					4.2%
	Total emissions:-		179231.0	100.00				% of total Boiler emissions removed -					4.0%

TABLE A-4.6.0

IDENTIFICATION FOR NOx PROCESS SOURCES

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Process #7	# Sources
Food & Beverage	Heat/resid	1	Heat/N. Gas	1										
Rubber & Plastics														
Textile Industries	Adipic Acid	1												
Paper & Allied Products	Lime Kiln	10	Recovery Boiler	10										
Metal Fabricating	CO gas	4	Coke Oven	8	Can Coat	5	Sinter. prod	1	Open Hearth	1	BF gas	5		
Transportation Equipment														
Non-metallic Products	Glass w. dist.	2	Glass w. N.G.	6	Cement kiln	9	PVC prod.	1	cement block	2	Agg/Asphalt	2	Salt Refining	1
Chem. & Chem. Products	Process Gas.	20	Cat. Crack	2	Cabot	10	Nitric Acid	2	Heaters	3	Pet. storage	1		
Other Major Groups	Incinerator	8												

TABLE A-4.7.1

NOx REDUCTION COSTS for PROCESSES Control Process # 1:- Low Excess Air

CAPITAL COSTS ($) :- PROCESSES

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Process #7	# Sources	Tot. Cap. Costs
Food & Beverage	77388	1		1											77388
Rubber & Plastics															0
Textile Industries		1													0
Paper & Allied Products		10		10											0
Metal Fabricating		4	30499	8		5	48060	1		1		5			292052
Transportation Equipment		0													0
Non-metallic Products	283374	2		6		9		1		2	20310	2		1	607367
Chem. & Chem. Products		20		2		10		2		3	18004	1			18004
Other Major Groups	237660	8													1901280
														Total :	2896090

OPERATING COSTS ($) :- PROCESSES

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Process #7	# Sources	Tot. Op. Costs
Food & Beverage	-14533	1		1											-14533
Rubber & Plastics															
Textile Industries		1													
Paper & Allied Products		10		10											
Metal Fabricating		4	-24592	8		5	-51045	1		1		5			-247781
Transportation Equipment															
Non-metallic Products	-4195694	2		6		9		1		2	-65949	2			-8523287
Chem. & Chem. Products		20		2		10		2		3	-25365	1		1	-25365
Other Major Groups	-17648	8													-141184
														Total :	-8952149

TABLE A-4.7.2

NOx REDUCTION COSTS for PROCESSES Control Option # 2:- Staged Combustion

CAPITAL COSTS ($) :- PROCESSES

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Process #7	# Sources	Tot. Cap. Costs
Food & Beverage	194891	1		1											194891
Rubber & Plastics															
Textile Industries		1													
Paper & Allied Products		10		10											
Metal Fabricating		4	60762	8		5	96429	1		1		5			582525
Transportation Equipment															
Non-metallic Products	425134	2		6		9		1		2	281703	2		1	1413674
Chem. & Chem. Products		20		2		10		2		3	213180	1			213180
Other Major Groups	45303	8													362424
														Total :	2766693

OPERATING COSTS ($) :- PROCESSES

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Process #7	# Sources	Tot. Op. Costs
Food & Beverage	4290	1		1											4290
Rubber & Plastics															
Textile Industries		1													
Paper & Allied Products		10		10											
Metal Fabricating		4	19369	8		5	39943	1		1		5			194895
Transportation Equipment															
Non-metallic Products	1196677	2		6		9		1		2	19437	2		1	2432228
Chem. & Chem. Products		20		2		10		2		3	7147	1			7147
Other Major Groups	9500	8													76000
														Total :	2714559

TABLE A-4.7.3

NOx REDUCTION COSTS for PROCESSES Control Option #3:- Selective Non-Catalytic Reduction

CAPITAL COSTS ($) :- PROCESSES

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Process #7	# Sources	Tot. Cap. Costs
Food & Beverage	151078	1	794649	1											945727
Rubber & Plastics															
Textile Industries	678545	1													678545
Paper & Allied Products	2708375	10	1273109	10											39814843
Metal Fabricating	492587	4	702650	8	1273109	5	1254873	1	2217911	1	1489842	5			24879087
Transportation Equipment															
Non-metallic Products	3683890	2	1154303	6	395581	9	16111093	1	395581	2	2200655	2	1169782	1	40327176
Chem. & Chem. Products	640081	20	3480583	2	282059	10	1270479	2	2242787	3	228976	1			32089678
Other Major Groups	405515	8													3244119
														Total :	141979175

OPERATING COSTS ($) :- PROCESSES

Industry	Process #1	# Sources	Process #2	# Sources	Process #3	# Sources	Process #4	# Sources	Process #5	# Sources	Process #6	# Sources	Process #7	# Sources	Tot. Op. Costs
Food & Beverage	33174	1	174492	1											207666
Rubber & Plastics															
Textile Industries	148997	1													148997
Paper & Allied Products	594714	10	279554	10											8742676
Metal Fabricating	108164	4	154290	8	279554	5	275549	1	487016	1	327144	5			5463033
Transportation Equipment															
Non-metallic Products	808921	2	253466	6	86863	9	3537728	1	86863	2	483227	2	256865	1	8855176
Chem. & Chem. Products	140551	20	764278	2	62111	10	278976	2	492479	3	50279	1			7046358
Other Major Groups	89044	8													712355
														Total :	31176261

TABLE A-4.7.5

NOx REDUCTION COSTS for ALL STREAMS Control Process # 1:- Low Excess Air

CAPITAL COSTS ($)

Industry Sector	Process Costs	BOILERS										Total Cap. Cost Boilers + Processes
		Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	
Food & Beverage	77388		27	51806	4	19013	14				1	550800
Rubber & Plastics			2	27188	1	32160	1					59349
Textile Industries			1			19568	7					136977
Paper & Allied Products			27	60666	3	23345	5	32781	6	73199	17	1543106
Metal Fabricating	292052		18	34054	4	26169	16			979128	1	1826099
Transportation Equipment			11	60450	3	22338	2		3			286937
Non-metallic Products	607367		6	25660	1	18526	7	20304	1	23394	1	786105
Chem. & Chem. Products	18004		32	78572	16	22081	20				5	1716759
Other Major Groups	1901280		34	31001	17	18836	36	20836	1			3127222
											Total :	10033354.26

OPERATING COSTS ($)

Industry Sector	Process Costs	BOILERS										Total Op. Cost Boilers + Processes
		Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	
Food & Beverage	-14533		27	-167013	4	-43132	14				1	-1286432
Rubber & Plastics			2	-168372	1	-274486	1					-442858
Textile Industries			1			-52896	7					-370272
Paper & Allied Products			27	-696516	3	-119356	5	-29769	6	3659	17	-2802739
Metal Fabricating	-247781		18	-274974	4	-169055	16			-177489	1	-4230044
Transportation Equipment			11	-690076	3	-101630	2	-28509	3			-2359014
Non-metallic Products	-8523287		6	-142971	1	-34563	7	-1469	1	-8476	1	-8918142
Chem. & Chem. Products	-25365		32	-975048	16	-97105	20				5	-17568226
Other Major Groups	-141184		34	-226966	17	-40010	36	-2676	1			-5442635
											Total :	-43420360

TABLE A-4.7.6

NOx REDUCTION COSTS for ALL STREAMS Control Process # 2:- Staged Combustion

CAPITAL COSTS ($)

Industry Sector	Process Costs	BOILERS										Total Cap. Cost Boilers + Processes
		Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	
Food & Beverage	194891		27	63919	4	243179	14				1	3855071
Rubber & Plastics			2	25519	1	633801	1					659319
Textile Industries			1			259664	7					1817648
Paper & Allied Products			27	77741	3	371877	5	65495	6	149306	17	5023777
Metal Fabricating	634448		18	36228	4	455788	16			200545	1	8272513
Transportation Equipment			11	77403	3	3419486	2	643434	3			9001482
Non-metallic Products	1413674		6	23134	1	228710	7	39622	1	46028	1	3123428
Chem. & Chem. Products	213180		32	105670	16	334307	20				5	8590043
Other Major Groups	362424		34	31466	17	227908	36	40725	1			9142745

Total : 49486026

OPERATING COSTS ($)

Industry Sector	Process Costs	BOILERS										Total Op. Cost Boilers + Processes
		Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	
Food & Beverage	4290		27	156605	4	11995	14				1	798633
Rubber & Plastics			2	47860	1	75123	1					122983
Textile Industries			1			14658	7					102607
Paper & Allied Products			27	197989	3	32793	5	23700	6	64631	17	1998855
Metal Fabricating	216402		18	78647	4	46354	16			53001	1	1325657
Transportation Equipment			11	197017	3	27956	2	22767	3			715265
Non-metallic Products	2429793		6	41015	1	9654	7	2759	1	7943	1	2549090
Chem. & Chem. Products	7147		32	278280	16	26692	20				5	4993453
Other Major Groups	76000		34	64957	17	11143	36	3632	1			1585031

Total : 14191573

TABLE A-4.7.7

NOx REDUCTION COSTS for ALL STREAMS Control Process # 3:- Selective Non-Catalytic Reduction

CAPITAL COSTS ($)

Industry Sector	Process Costs	BOILERS										Total Cap. Cost Boilers + Processes
		Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	
Food & Beverage	945727	711930	27	894116	4	328170	14			1692054	1	30030725
Rubber & Plastics		1236264	2	386966	1	1186622	1					4046115
Textile Industries	678545	354182	1			377651	7					3676286
Paper & Allied Products	39814843	894258	27	1045276	3	664183	5	872489	6	751629	17	88429202
Metal Fabricating	24879987	616586	18	547983	4	846265	16			1910098	13	76541069
Transportation Equipment		643852	11	1041948	3	593675	2	847572	3			13938284
Non-metallic Products	40327176	625317	6	347385	1	282277	7	147766	1	349834	1	46899995
Chem. & Chem. Products	32089678	827975	32	1327387	16	575327	20			799476	5	95327007
Other Major Groups	3244120	565843	34	479658	17	971393	36	195850	1			65802965
											Total :	424691648

O ($)

Industry Sector	Process Costs	BOILERS										Total Op. Cost Boilers + Processes
		Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	
Food & Beverage	207668	156329	27	196335	4	72061	14			371551	1	6594314
Rubber & Plastics		271466	2	84972	1	260565	1					888469
Textile Industries	148999	77773	1			82927	7					807259
Paper & Allied Products	8742764	196366	27	229528	3	145845	5	191586	6	165047	17	19417775
Metal Fabricating	5463088	135393	18	120329	4	185828	16			419430	13	16807313
Transportation Equipment		141381	11	228797	3	130362	2	186115	3			3060546
Non-metallic Products	8855265	137310	6	76281	1	61984	7	32447	1	76818	1	10565567
Chem. & Chem. Products	7046430	181811	32	291475	16	126334	20			175553	5	20932434
Other Major Groups	712362	124251	34	105326	17	213304	36	43006	1			14449381
											Total :	93523157

TABLE A-4.7.8

NOx REDUCTION COSTS for ALL STREAMS Control Option # 4:- Selective Catalytic Reduction

CAPITAL COSTS ($) :- ALL STREAMS

Industry Sector	Process Costs	BOILERS										Total Cap. Cost Boilers + Processes
		Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	
Food & Beverage	1077820	3329135	27	4181079	4	1534594	14			7912408	1	137085498
Rubber & Plastics		5781034	2	1809538	1	5548696	1					18920502
Textile Industries	3173021	1656231	1			1765978	7					17191100
Paper & Allied Products	186182723	4181744	27	4887935	3	3105862	5	4079945	6	3514781	17	413513872
Metal Fabricating	89841731	2883286	18	2562485	4	3957317	16			4467013	13	273379963
Transportation Equipment		3010791	11	4872371	3	2776149	2	3963427	3			85178396
Non-metallic Products	285758707	2924114	6	1624445	1	1319986	7	690983	1	1635898	1	316492617
Chem. & Chem. Products	150066396	3871789	32	5699738	16	2690606	20			3738522	5	437664182
Other Major Groups	15170196	2646003	34	2242985	17	1457351	36	915036	1			196645523
											Total :	1876070753

OPERATING COSTS ($) :- ALL STREAMS

Industry Sector	Process Costs	BOILERS										Total Op. Cost Boilers + Processes
		Nat. Gas	# Sources	Distillate	# Sources	Residual	# Sources	Coal	# Sources	Other	# Sources	
Food & Beverage	189560	585507	27	735341	4	269894	14			1391583	1	24109709
Rubber & Plastics		1016731	2	318250	1	975904	1					3327615
Textile Industries	558050	291287	1			310589	7					3023459
Paper & Allied Products	32744610	735458	27	859658	3	546239	5	717554	6	618157	17	72728139
Metal Fabricating	15800781	507094	18	450673	4	695987	16			785629	13	48080137
Transportation Equipment		529518	11	856921	3	488251	2	697062	3			11463154
Non-metallic Products	50257037	514274	6	285697	1	232151	7	121526	1	287711	1	56662695
Chem. & Chem. Products	26392705	680945	32	1002433	16	473206	20			657507	5	76973539
Other Major Groups	2668036	465362	34	394482	17	256309	36	161071	1			34584740
											Total :	330951187

TABLE A-4.8.1

NITROGEN OXIDE REMOVAL COSTS. Control Method # 1:- LOW EXCESS AIR

Industry	Nitrogen oxide emissions (T/year)				Control Costs $1987 Cdn.								
	Process Emissions	% of Total	Total Boilers	% of Total	Capital $ Cdn.	Operating $ Cdn.	Annual $ Cdn.	Plant Life	Tonnes Controlled	Control Eff'y %	Tonnes Removed	Cost/ Tonne	Overall Eff'y %
Food & Beverage	54.9	0.16	2817.9	6.68	550800	-1286432	-1221735	20	720.6	20	144.1	-8477.2	5.0%
Rubber & Plastics	0.0		385.9	0.92	59349	-442858	-435886	20	215.6	20	43.1	-10108.7	11.2%
Textile Industries	497.1	1.49	682.8	1.62	136977	-370272	-354183	20	608.2	20	121.6	-2911.7	10.3%
Paper & Allied Products	5508.4	16.53	5920.3	14.04	1543106	-2802739	-2621486	20	6019.1	20	1203.8	-2177.6	10.5%
Metal Fabricating *	4580.9	13.75	10231.5	24.26	1851978	-4257529	-4039996	20	3026.4	20	605.3	-6674.6	4.1%
Transportation Equipment	0.0		2099.2	4.98	286937	-2359014	-2325310	20	637.9	20	127.6	-18226.3	6.1%
Non-metallic Products	8761.4	26.29	1065.0	2.53	706105	-8918142	-8825806	20	2100.7	20	420.1	-21006.8	4.3%
Chem. & Chem. Products *	13283.2	39.87	15303.5	36.29	1716759	-17568226	-17366576	20	7194.4	20	1438.9	-12069.5	5.0%
Other Major Groups	634.2	1.90	3663.3	8.69	3127223	-5442635	-5075313	20	2418.8	20	483.8	-10491.4	11.3%
TOTALS	33320.1	100.0	42169.4	100.0	10059233	-43447846	-42266292		22941.7		4588.3	-9211.7	6.1%
% of overall TOTALS	44.1		55.9										
	Total Emissions:-		75489.5	100.0					% of Total emissions controlled:				30.39%
									% of Total emissions removed:				6.08%

TABLE A-4.8.2

NITROGEN OXIDE REMOVAL COSTS. Control Option #2:- STAGED COMBUSTION

Industry	Nitrogen oxide emissions (T/year)				Capital $ Cdn.	Operating $ Cdn.	Annual $ Cdn.	Control Plant Life	Costs $1987 Cdn. Tonnes Controlled	Control Eff'y %	Tonnes Removed	Cost/ Tonne	Overall Eff'y %
	Process Emissions	% of Total	Total Boilers	% of Total									
Food & Beverage	54.9	0.16	2817.9	6.68	3855071	798633	1251448	20	720.6	40	288.2	4341.7	10.0%
Rubber & Plastics			385.9	0.92	659319	122983	200426	20	215.6	40	86.2	2324.0	22.3%
Textile Industries	497.1	1.49	682.8	1.62	1817648	102607	316108	20	608.2	40	243.3	1299.4	20.6%
Paper & Allied Products	5508.4	16.53	5920.3	14.04	5023777	1998855	2588946	20	6019.1	40	2407.6	1075.3	21.1%
Metal Fabricating	4580.9	13.75	10231.5	24.26	8272513	1325657	2297343	20	3026.4	40	1210.6	1897.8	8.2%
Transportation Equipment			2099.2	4.98	9001482	715265	1772575	20	637.9	40	255.2	6946.9	12.2%
Non-metallic Products	8761.4	26.29	1065.0	2.53	3123428	2549090	2915966	20	2100.7	40	840.3	3470.2	8.6%
Chem. & Chem. Products	13283.2	39.87	15303.5	36.29	8590043	4993453	6002436	20	7194.4	40	2877.8	2085.8	10.1%
Other Major Groups	634.2	1.90	3663.3	8.69	9142745	1585031	2658935	20	2418.8	40	967.5	2748.2	22.5%
TOTALS	33320.1	100.0	42169.4	100.0	49486026	14191573	20004183		22941.7		9176.7	2179.9	12.2%
% of overall TOTALS	44.1		55.9						% of NOx emissions controlled:				30.39%
	Total Emissions:-		75489.5	100.0					% of NOx emissions removed:				12.16%

TABLE A-4.8.3

NITROGEN OXIDE REMOVAL COSTS. Control Option # 3:- SELECTIVE NON-CATALYTIC REDUCTION.

Industry	Nitrogen oxide emissions (T/year)				Control Costs $1987 Cdn.								
	Process Emissions	% of Total	Total Boilers	% of Total	Capital $ Cdn.	Operating $ Cdn.	Annual $ Cdn.	Plant Life	Tonnes Controlled	Control Eff'y %	Tonnes Removed	Cost/ Tonne	Overall Eff'y %
Food & Beverage	54.9	0.16	2817.9	6.68	30030725	6594313	10542566	15	2679.5	60	1607.7	6557.5	56.0%
Rubber & Plastics			385.9	0.92	4046117	888469	1420427	15	385.9	60	231.5	6134.7	60.0%
Textile Industries	497.1	1.49	682.8	1.62	3676286	807259	1290594	15	1119.7	60	671.8	1921.1	56.9%
Paper & Allied Products	5508.4	16.53	5920.3	14.04	88429202	19417775	31043897	15	11244.2	60	6746.5	4601.5	59.0%
Metal Fabricating	4580.9	13.75	10231.5	24.26	76541069	16807313	26870457	15	14141.2	60	8484.7	3166.9	57.3%
Transportation Equipment			2099.2	4.98	13938284	3060646	4893164	15	2065.5	60	1239.3	3948.3	59.0%
Non-metallic Products	8761.4	26.29	1065.0	2.53	46899995	10565567	16731686	15	8838.8	60	5303.3	3155.0	54.0%
Chem. & Chem. Products	13283.2	39.87	15303.5	36.29	95327007	20932434	33465436	15	26049.2	60	15629.5	2141.2	54.7%
Other Major Groups	634.2	1.90	3663.3	8.69	65802965	14449381	23100745	15	3353.4	60	2012.0	11481.4	46.8%
TOTALS	33320.1	100.0	42169.4	100.0	424691649	93523157	149358972		69877.3		41926.4	3562.4	55.5%
% of overall TOTALS	44.1		55.9						% of Total emissions controlled:				92.57%
	Total Emissions:-		75489.5	100.0					% of Total emissions removed:				55.54%

TABLE A-4.8.4

NITROGEN OXIDE REMOVAL COSTS. Control Option # 4:- SELECTIVE CATALYTIC REDUCTION.

Industry	Nitrogen oxide emissions (T/year)				Control Costs $1987 Cdn.								
	Process Emissions	% of Total	Total Boilers	% of Total	Capital $ Cdn.	Operating $ Cdn.	Annual $ Cdn.	Plant Life	Tonnes Controlled	Control Eff'y %	Tonnes Removed	Cost/ tonne	Overall Eff'y %
Food & Beverage	54.9	0.16	2817.9	6.68	137085498	24109709	42132857	15	2679.5	85	2277.6	18499.0	79.3%
Rubber & Plastics	0.0	0.00	385.9	0.92	18920502	3327615	5815165	15	385.9	85	328.0	17728.4	85.0%
Textile Industries	497.1	1.49	682.8	1.62	17191100	3023459	5283638	15	1119.7	85	951.7	5551.6	80.7%
Paper & Allied Products	5508.4	16.53	5920.3	14.04	413513872	72726139	127092369	15	11244.2	85	9557.6	13297.6	83.6%
Metal Fabricating	4580.9	13.75	10231.5	24.26	273379063	48080137	84022315	15	14141.2	85	12020.0	6990.2	81.1%
Transportation Equipment			2099.2	4.98	65178396	11463154	20032404	15	2065.5	85	1755.7	11410.1	83.6%
Non-metallic Products	8761.4	26.29	1065.0	2.53	316492617	56662695	98273175	15	8638.8	85	7513.0	13080.5	76.5%
Chem. & Chem. Products	13283.2	39.87	15303.5	36.29	437664182	76973539	134514902	15	26049.2	85	22141.8	6075.2	77.5%
Other Major Groups	634.2	1.90	3663.3	8.69	196645523	34584740	60438469	15	3353.4	85	2850.3	21203.9	66.3%
TOTALS	33320.1	100.0	42169.4	100.0	1876070753	330951187	577605294		69877.3		59395.7	9724.7	78.7%
% of overall TOTALS	44.1		55.9										
	Total Emissions:-		75489.5	100.0					% of NOx emissions controlled:				92.57%
									% of NOx emissions removed:				78.68%

TABLE A-4.9

EFFECTS OF REFINERY FUEL OIL DESULPHURISATION ON SO2 EMISSIONS

SULPHUR DIOXIDE EMISSIONS (T/year) Control process :- REFINERY FUEL DESULPHURISATION

Industry	Sulphur dioxide emissions				SOx Reductions Case 2		SOx Reductions Case 3		SOx Reductions Case 4		SOx Reductions Case 5 (*)		SOx Reductions Case 6	
	Boiler Emissions		Total Boilers	% of Total	Dist.	Resid.	Dist	Resid.	Dist.	Resid.	Dist.	Resid.	Dist.	Resid.
	Distillate	Residual												
Primary Metals	9.7	0.0	9.7	0.01	6.3	0.0	0.1	0.0	6.3	0.0	-0.1	0.0	6.3	0.0
Food & Beverage	171.4	895.6	1067.0	0.60	111.7	0.0	1.5	667.6	112.2	667.8	-0.9	793.3	111.4	793.5
Textile Industries	20.8	2882.7	2903.5	1.62	13.6	0.0	0.2	2148.8	13.6	2149.3	-0.1	2553.5	13.5	2554.1
Paper & Allied Products	992.7	2836.2	3828.9	2.14	646.8	0.0	8.6	2114.1	649.8	2114.7	-5.2	2512.3	645.3	2512.9
Metal Fabricating	239.3	3161.8	3401.1	1.90	155.9	0.0	2.1	2356.8	156.6	2357.4	-1.3	2800.7	155.5	2801.4
Transportation Equipment	194.7	787.9	982.6	0.55	126.9	0.0	1.7	587.3	127.5	587.5	-1.0	697.9	126.6	698.1
Non-metallic Products	51.0	828.3	879.3	0.49	33.2	0.0	0.4	617.4	33.4	617.6	-0.3	733.7	33.2	733.9
Chem. & Chem. Products	12760.9	15877.1	28638.0	15.98	8315.0	0.0	110.0	11834.8	8353.3	11838.0	-67.1	14063.9	8294.6	14067.1
Other Major Groups	936.8	3195.6	4132.4	2.31	610.4	0.0	8.1	2382.0	613.2	2382.6	-4.9	2830.7	608.9	2831.3
TOTALS	15377.3	30465.2	45842.5	25.58	10019.8	0.0	132.6	22708.8	10066.0	22714.9	-80.9	26986.1	9995.2	26992.2
% of overall Emissions	8.58	17.00	25.58	0.01	5.59	0.00	0.07	12.67	5.62	12.67	-0.05	15.06	5.58	15.06
Total % of Overall Emissions		25.6		25.6		5.6		12.7		18.3		15.0		20.6
Total SOx Emissions	179231.0			100.00										

* Note: Increased conversion of HFO to LFO reduces emissions from HFO versus Case 3 but results in slightly higher sulphur emissions from LFO

TABLE A-4.10

COSTS of FUEL OIL DESULPHURISATION ('000s of dollars, CDN 1987)

Control process :- REFINERY FUEL DESULPHURISATION

Industry	Sulphur dioxide emissions (T/yr)				Costs Case 2		Costs Case 3		Costs Case 4		Costs Case 5		Costs Case 6	
	Boiler Emissions		Total Boilers	% of Total	Dist.	Resid	Dist.	Resid.	Dist.	Resid.	Dist	Resid.	Dist.	Resid.
	Dist'l'te	Residual												
Primary Metals	9.7	0.0	9.7	0.01	1.93	0.00	0.07	0.00	4.83	0.00	0.03	0.00	3.22	0.00
Food & Beverage	171.4	895.6	1067.0	0.60	34.03	0.00	1.24	561.70	85.39	508.23	0.50	442.59	56.83	404.77
Textile Industries	20.8	2882.7	2903.5	1.62	4.13	0.00	0.15	1807.97	10.36	1635.86	0.06	1424.60	6.90	1302.83
Paper & Allied Products	992.7	2836.2	3828.9	2.14	197.09	0.00	7.18	1778.81	494.58	1609.48	2.91	1401.62	329.14	1281.82
Metal Fabricating	239.3	3161.8	3401.1	1.90	47.51	0.00	1.73	1983.02	119.22	1794.25	0.70	1562.52	79.34	1428.97
Transportation Equipment	194.7	787.9	982.6	0.55	38.66	0.00	1.41	494.15	97.00	447.11	0.57	389.37	64.56	356.09
Non-metallic Products	51.0	828.3	879.3	0.49	10.13	0.00	0.37	519.49	25.41	470.04	0.15	409.34	16.91	374.35
Chem. & Chem. Products	12760.9	15877.1	28638.0	15.98	2533.58	0.00	92.34	9957.79	6357.69	9009.88	37.45	7846.27	4231.07	7175.63
Other Major Groups	936.8	3195.6	4132.4	2.31	185.99	0.00	6.78	2004.22	466.73	1813.43	2.75	1579.23	310.61	1444.25
TOTALS	15377.3	30465.2	45842.5	25.58	3053.0	0.0	111.3	19107.2	7661.2	17288.3	45.1	15055.5	5098.6	13768.7
% of overall Emissions	8.58	17.00	25.58	0.01	5.59	0.00	0.08	12.68	5.62	12.68	0.04	15.06	5.58	15.06
Total % of Overall Emissions		25.6		25.6		5.6		12.8		18.3		15.1		20.6
Total SOx Emissions	179231.0			100.00										

TABLE A-4.11

Estimated Overall Emissions Reductions of SOx from Fuel Usage

SULPHUR DIOXIDE EMISSIONS (T/year) Control process :- REFINERY FUEL DESULPHURISATION

		Usage at Refinery HFO	LFO	Saleable oil HFO	LFO	Totals
Simulated usage cubic metres per year		813175	5097	4240636	4064857	9123765
Specific gravity		0.998	0.8644	0.998	0.8644	
Tonne per year		811549	4406	4232155	3513662	8561771
Sulphur %		1.435	0.287	1.646	0.287	
SOx emitted (T per year)		23291	25	139323	20168	182807.
Case 1	Reduction in SOx		(BASE CASE)			
	% reduction					
Case 2	Reduction in SOx		16.0		13142.0	13158
	% reduction		63.3		65.2	7.2
Case 3	Reduction in SOx	4998.0		103840.0	174.0	109012
	% reduction	21.5		74.5	0.9	59.6
Case 4	Reduction in SOx	5014.0	16.0	103866.0	13202.0	122098
	% reduction	21.5	63.3	74.6	65.5	66.8
Case 5	Reduction in SOx	4170.0		123414.0	-106.0	127478
	% reduction	17.9		88.6	-0.5	69.7
Case6	Reduction in SOx	4186.0	16.0	123426.0	13104.0	140732
	% reduction	18.0	63.3	88.6	65.0	77.0

TABLE A-4.12

COSTS of FUEL OIL DESULPHURISATION
($ per Tonne SOx removed)

Case Number	Capital Cost (millions)	Annual Cost (millions)	Sulphur removed (Tonnes)	Emission Reduction (SOx) Refinery	Consumers	Cost per Tonne SOx
1 *	0.00	0.00	0	0	0	0.0
2	2.07	6.99	11472	80	22864	304.7
3	372.00	91.60	54436	4999	103874	841.3
4	373.71	104.90	65916	5094	126738	795.7
5	415.37	71.02	63646	4170	123122	557.9
6	417.30	76.75	75224	4266	146182	510.1

NOTES:- (1) Capital charges of 25 % are included in annual costs
(2) Operating costs are dependent on crude prices, $34 per Bbl used.
(3) HFO and Residual Pitch disposal costs have been included.
(4) Diesel and kerosene products are included in emission reduction quantities

(*) Base case

APPENDIX B

COSTING PROCEDURES, FUEL DATA
QUALITY OF INFORMATION ON CONTROLS

APPENDIX B - LIST OF TABLES

B-1.1 Quality of Information on Controls - SO_2

B-1.2 Quality of Information on Controls - NO_x

B-1.3 Annualized Cost Equation

B-2.1 Nomenclature Used in Cost Algorithms

B-2.2 Capital Cost Components

B-2.3 Operating and Maintenance Costs Components

B-2.4 Calculations Common to Cost Algorithms

B-2.5 Cost Equations for Low Excess Air Applied to Industrial Boilers

B-2.6 Cost Equations for Staged Combustion Air Applied to Pulverized Coal-Fired Boilers

B-2.7 Cost Equations for Staged Combustion Air Applied to Residual Oil-Fired Boilers

B-2.8 Cost Equations for Lime Spray Drying FGD Systems with PM Removal

B-2.9 Cost Equations for Sodium Scrubbing FGD Systems

B-2.10 General Design Specifications for FGD System for SO_2 Control

B-3.1 Estimated Capital Investment for Selective Catalytic Reduction

B-3.2 Estimated Operating Costs for Selective Catalytic Reduction

B-3.3 Estimated Capital Investment for Selective Non-Catalytic Reduction

B-3.4 Estimated Operating Costs for Selective Non-Catalytic Reduction

B-3.5 Costing Algorithm for SCR/SNCR

B-4.1 Fuel Switching Cost Algorithm

B-4.2 Limestone Flue Gas Desulphurization Algorithm

B-5.1 Fuel Characteristics

B-5.2 Characteristics of "Unconventional" Fuels

APPENDIX B: COSTING PROCEDURES, FUEL DATA, QUALITY OF INFORMATION ON CONTROLS

B.1 Introduction

Costing algorithms and fuel characteristics used in the economic analysis of control strategies are presented in this Appendix. With the exception of the fuel switching algorithm, basic cost equations follow those outlined by the Radian Corporation (1984) and SRI International (1980). The quality of information respecting various control technologies is summarized in Tables B.1.1 and B.1.2.

Algorithms in this Appendix are grouped according to source with those developed by the EPA used for costing both NO_x and SO_2 control strategies, those based on SRI International (1980) on ETEP strictly for NO_x control, and fuel switching for SO_2 control only. All costs are converted to 1987 Canadian dollars based on Statistics Canada escalation factors. The calculation of annualized costs is shown in Table B.1.3.

B.2 Radian Corporation Costing Algorithms

Cost correlations developed by the Radian Corporation (1980) consist of a set of generic equations common to all control strategies and empirical relationships developed on a process by process basis. Nomenclature is common throughout all algorithms and is summarized in Table B.2.1.

Generic cost equations are outlined in Tables B.2.2 and B.2.3 and summarized algebraically in Table B.2.4. Process specific algorithms are summarized in Tables B.2.5 to B.2.9 for the following control processes:

- low excess air, coal, oil and gas boilers (NO_x control)
- low excess air, pulverized coal (NO_x control)
- staged combustion (NO_x control)

- sodium scrubbing FGD system (SO_2 control)
- spray drying/dry scrubbing (SO_2 and particulate control)

General design specifications for FGD systems are shown in Table C.2.10..

B.3 SRI International Costing Algorithms

Costing algorithms for NO_x control by selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) are based on data by SRI (1980). A power law correlation of the form:

$$COST_1 = COST_{REF} \times \left[\frac{capacity_1}{capacity_{REF}}\right]^{0.7}$$

was used to calculate capital and operating costs for facilities. For costing purposes, volumetric flowrate was chosen as a representative measure of capacity with a value of 1.8 million acfm calculated for the reference facility.

Cost estimates as developed by SRI for the reference facility are shown in Tables B.3.1 and B.3.2 for SCR and Tables B.3.3 and B.3.4 for SNCR controls respectively. The algorithms used for costing purposes are shown in Table B.3.5. This table also summarizes estimates of operating costs component costs according to the equation:

$$\text{component cost} = OC_1 * \left[\frac{CC_{REF}}{OC_{REF}}\right]$$

where

OC_1 = operating cost of facility being costed;
CC_{REF} = component cost of reference facility, and
OC_{REF} = operating cost of the reference facility

B.4 Fuel Switch Algorithm

Capital costs for fuel switching were estimated using the Radian Corporation's "Cost Equations for Low Excess Air Applied to Industrial Boilers" as presented in Table B.2.5. Capital costs were calculated based on a natural gas feed rate which provides an equivalent heat input as the process under evaluation. The calculated capital cost was then multiplied by a factor of 1.5 to account for equipment modification costs.

Operating costs, calculated using the algorithm outlined in Table B.4.1, represent the savings (increase) in fuel costs resulting from the fuel switch. All other operating costs were assumed constant.

The costs, of the fuels, used were obtained from suppliers and industry associations by telephone conversations. The values represent the best estimates which could be made from the ranges of costs disclosed by those sources. None of the information sources were prepared to quote firm costs unless a specific situation was under consideration.

B.5 Fuel Characteristics

Data pertaining to fuel characteristics are shown in Tables B.3.1 and B.3.2 for conventional and unconventional fuels respectively. Heat and sulphur (S or SO_2) content data were used to calculate heat inputs and/or gas flowrates required in the costing algorithms.

Table B.1.1

QUALITY OF INFORMATION ON CONTROLS - SO_2

SO_2 Control	Rating[1]	Tech-nology[2]	Cost[3]
Coal cleaning	NA		
Ore beneficiation	G	T_1	C_1
Fuel switching	G	T_1	C_1
Petroleum fuel desulphurization	G	T_1	C_1
Raw material change	NA		
Operating changes	NA		
Equipment changes	NA		
Fuel additives	P	T_3	C_3
Dry lime addition to fuel	P	T_2	C_3
Lime injection modified burners	F	T_1	C_2
Lime/limestone scrubbing	G	T_1	C_1
Duel alkali scrubbing	G	T_1	C_1
Sodium carbonate scrubbing	G	T_1	C_1
Major process changes	F	T_1	C_1
Wellman-Lord process	G	T_1	C_1
Cominco process	G	T_1	C_1
Citrate & Stauffer process	G	T_1	C_1
Pearson-Peck process	F	T_2	C_2
Tail gas cleaning	G	T_1	C_1
Irradiation technology	F	T_3	C_3
Dry lime injection	G	T_1	C_1
Spray drying process	G	T_1	C_1
Poli process	F	T_2	C_2

1. Rating: G - Good; F - Fair; P - Poor, NA - Not Available.

2. Technology: T_1 - Proven; T_2 - Tentative; T_3 - Unproven.

3. Cost: C_1 - Established; C_2 - Approximate; C_3 - Unknown.

Table B.1.2

QUALITY OF INFORMATION ON CONTROLS - NO_X

NO_x Control	Rating[1]	Technology[2]	Cost[3]
Fuel switching	G	T_1	C_1
Fuel modification	NA (except refineries)		
Low excess air	G	T_1	C_1
Flue Gas recirculation	G	T_1	C_1
Staged combustion	G	T_1	C_1
Low NO_x Burners	G	T_1	C_1
Lime injection modified burner	F	T_2	C_2
Dry lime addition to fuel	P	T_3	C_3
Fuel additives	P	T_3	C_3
Selective catalytic reduction	G	T_1	C_1
Selective non-catalytic reduction	G	T_1	C_1
Copper oxide absorption	P	T_3	C_3
Irradiation technology	E	T_3	C_3
Other combined technologies	P	T_3	C_3

1. Rating: G - Good; F - Fair; P - Poor, NA - Not Available.

2. Technology: T_1 - Proven; T_2 - Tentative; T_3 - Unproven.

3. Cost: C_1 - Established; C_2 - Approximate; C_3 - Unknown.

Table B.1.3

ANNUALIZED COST EQUATION

$$CRF = \frac{i\,(1 + i)^n}{(1 + i)^n - 1}$$

$$AC = OC + CRF * CC$$

where:

- AC = annualized cost
- CC = capital cost
- CRF = capital recovery factor
- i = interest rate, assumed to be 10%
- OC = yearly operating costs
- n = control system life

TABLE B-2.1 NOMENCLATURE USED IN COST ALGORITHMS

1. Capital Costs (1978 dollars)

EQUP	=	Equipment
INST	=	Installation
TD	=	Total Direct
IND	=	Indirect (Engineering, Field, Construction, Start-up, and other miscellaneous costs)
TDI	=	Total Direct and Indirect
CONT	=	Contingencies
TK	=	Turnkey
LAND	=	Land
WC	=	Working Capital
TOTL	=	Total Capital

2. Operation and Maintenance Costs (1978 dollars/year)

DL	=	Direct Labor
SPRV	=	Supervision Labor
MANT	=	Maintenance Labor
SP	=	Spare Parts
ELEC	=	Electricity
UC	=	Utilities and Chemicals
WTR	=	Water
SW	=	Solid Waste Disposal
SLG	=	Sludge Waste Disposal
LW	=	Liquid Waste Disposal
SC	=	Sodium Carbonate
LMS	=	Limestone
LIME	=	Lime
FUEL	=	Fuel
TDOM	=	Total Direct Operation and Maintenance
OH	=	Overhead
TOTL	=	Total Operation and Maintenance

3. Annualized Costs (1978 dollars/year)

CR	=	Capital Recovery
WCC	=	Working Capital Charges
MISC	=	Miscellaneous (G & A, Taxes, Insurance)
TCC	=	Total Capital Charges
TOTL	=	Total Annualized Charges

TABLE B-2.1 (Continued)

4. Boiler Specifications

Q = Thermal Input (10^6 Btu/hr) MW)[b]
FLW = Flue Gas Flowrate (acfm) (m^3/s)[b]
CF = Capacity Factor (-)[c]
BCRF = Capital Recovery Factor for Boiler System

5. Fuel Specifications

FC = Fuel Cost ($/$10^6$ Btu) ($MJ)[b]
H = Heating Value (Btu/lb) (KJ/kg)[b]
S = Sulfur Content (percent by weight)
A = Ash Content (percent by weight)
N = Fuel Nitrogen Content (percent by weight)

6. SO_2 Control Specifications

UNCSO2 = Uncontrolled SO_2 Emissions (lb/10^6 Btu) (ng/J)[b]
CTRSO2 = Controlled SO_2 Emissions (lb/10^6 Btu) (ng/J)[b]
EFFSO2 = SO_2 Removal Efficiency (percent)
CRFSO2 = Capital Recovery Factor for SO_2 Control System

7. PM Control Specifications

UNCPM = Uncontrolled PM Emissions (lb/10^6 Btu) (ng/J)[b]
CTRPM = Controlled PM Emissions (lb/10^6 Btu) (ng/J)[b]
EFFPM = PM Removal Efficiency (percent)
CRFPM = Capital Recovery Factor for PM Control System

8. Cost Rates

ELEC = Electricity Rate ($/kw-hr)
WTR = Water Rate ($/$10^3$ gal) ($/$m^3$)[b]
ALIME = Lime Rate ($/ton) ($/kg)[b]
ALS = Limestone Rate ($/ton) ($/kg)[b]
SASH = Sodium Carbonate Rate ($/ton) ($/kg)[b]
SLDG = Sludge Disposal Rate ($/ton) ($/kg)[b]
SWD = Solid Waste Disposal Rate ($/ton) ($/kg)[b]
LWD = Liquid Waste Disposal Rate ($/$10^3$ gal) ($/$m^3$)[b]
DLR = Direct Labor Rate ($/man-hr)
SLR = Supervision Labor Rate ($/man-hr)
AMLR = Maintenance Labor Rate ($/man-hr)

TABLE B-2.1 (Continued)

9. Miscellaneous

S1	=	Heat Specific Sulfur Removal (kg S/1000 MJ)
S2	=	Time Specific Sulfur Removal (kg S/hr)
LF	=	Labor Factor (-)[d]

10. NO_x Control Specifications

FFAC	=	F-Factor (dscf/10^6 Btu)
UNCEA	=	Uncontrolled Excess Air (%)
CTREA	=	Controlled Excess Air (%)
PRCT	=	Percent Flame Extension Due to Staging
DELT	=	Change in the flue gas exit temperature due to the elimination of the air preheater or a reduction in its effectiveness.
$CRFNO_x$	=	Capital Recovery Factor for NO_x Control System

[a]Cost categories are not mutually exclusive. For example, some costing routines include electricity and waste cost in the utilities category while other calculate these cost separately.

[b]FGD algorithms use metric units.

[c](-) factor presented as fraction not as percent.

Table B.2.2

CAPITAL COST COMPONENTS[a]

(1) Direct Costs

Equipment
+ Installation
= Total Direct Costs

(2) Indirect Costs

Engineering	(10% of total direct costs)
+ Construction and Field Expenses	(10% of total direct costs)
+ Construction Fees	(10% of total direct costs)
+ Start Up Costs	(2% of total direct costs)
+ Performance Costs	(1% of total direct costs)
= Total Indirect Costs	

(3) Contingencies = 20% of (Total Indirect + Total Direct Costs)

(4) Total Turnkey Cost = Total Indirect Cost + Total Direct Cost
+ Contingencies

(5) Working Capital

(6) Total Capital Cost = Total Turnkey + Working Capital

Note:

[a] Boiler and each control system costed separately; factors apply to cost of boiler or control system considered; i.e., the engineering cost for the SO_2 control system is 10% of the direct cost of the SO_2 control system.

TABLE B-2.3 OPERATING AND MAINTENANCE COSTS COMPONENTS[a]

(1) Direct Operating Costs

Operating Labor
+ Supervision
+ Maintenance Labor, Replacement Parts and Supplies
+ Electricity
+ Water
+ Steam
+ Waste Disposal
  Solids (Fly ash and bottom ash)
  Sludge
  Liquid
+ Chemicals

Total Non-Fuel O&M
+ Fuel

= Total Direct Operating Costs

(2) Indirect Operating Costs (Overhead)

Payroll (30% Operating Labor)
+ Plant (26% of Operating Labor + Supervision + Maintenance Costs + Replacement Parts)

(3) Total Annual Operating and Maintenance Costs = Total Direct + Total Indirect Costs

[a]Boilers and control systems are costed separately; factors apply to boiler or control system being considered, (i.e., payroll overhead for FGD system is 30% of the labor requirement for the FGD system).

Table B.2.4

CALCULATIONS COMMON TO COST ALGORITHMS

1. Capital Costs

TD[a] = EQUP + INST
IND = 0.333 * TD[b]
TDI = TD + IND
CONT = 0.20 * TDI
WC[c] = 0.25 * TDOM
TK = EQUIP + INST + IND
TOTL = TK + WC

2. Operation and Maintenance Costs

FUEL = CF * Q * FC * 8760
TDO = Sum of all O&M Costs other than OH
OH = 0.30 * DL + 0.26 * (DL + SPRV + MANT + SP)
TOTL = TDOM + OH

3. Annualized Costs

CR = CRF * TK
WCC = 0.10 * WC
MISC = 0.04 * TK
TCC = CR + WCC + MISC
TOTL = TCC + TOTL O&M Costs

4. Labour Factors

LF = 1 if CF > 0.7
LF = 0.5 + 2.5 * (CF - 0.5) if $0.5 \leq CF \leq 0.7$
LF = 0.5 if CF < 0.5

Note:

[a] FGD system cost algorithms compute TD without prior computation of EQUP and INST.

[b] Some algorithms compute IND explicitly as a function of boiler and/or control device specifications.

[c] Assumes 3 months of direct annual operating costs.

TABLE B-2.5 COST EQUATIONS FOR LOW EXCESS AIR APPLIED TO INDUSTRIAL BOILERS

Routine Code: LEA

Capital Costs:

Coal: EQUIP = 46.22(Q) + 6496
INST and IND = 21.50(Q) + 1123

Oil and Gas: EQUIP = 31.38(Q) + 5185
INST and IND = 11.37(Q) + 1161

Annual Costs:

SP[b] = 0.05 (TK)
FUEL = -.00055(FC)(Q)(CF)(FFAC)(UNCEA - CTREA)

[a]Algorithm assumes a flue gas temperature of 400°F and the ambient air temperature to be 77°F.

[b]Spare parts costs consist of the costs for spare parts, maintenance labor, and maintenance materials.

TABLE B-2.6 COST EQUATIONS FOR STAGED COMBUSTION AIR APPLIED TO PULVERIZED COAL-FIRED BOILERS

Routine Code: SCA

Capital Costs:

EQUIP = 65 (Q) + 13000
INST and IND = 60 (Q) + 2000

Annual Costs:

SP[a] = 0.05 (TK)
ELEC = 105 (Q)(CF)
FUEL = 21.9 (FC)(Q)(CF)

[a] Spare parts costs consist of the costs for spare parts, maintenance labor, and maintenance materials.

TABLE B-2.7 COST EQUATIONS FOR STAGED COMBUSTION AIR APPLIED TO RESIDUAL OIL-FIRED BOILERS (fuel N >0.23 wt. percent)

(30 - 250 x 10^6 Btu/hr)

Routine Code: SCA

Capital Costs:

$$TK = 1000 [(Q)(PRCT)\ 0.0536 + 2.56\ (PRCT)]$$

where:

PRCT = 30; when N >0.6
PRCT = 81.1(N) - 18.7 when 0.23 <N <0.6

Annual Costs:

SP^a = 0.05 (TK)
ELEC = 102 (Q)(CF)
FUEL = 21.9 (FC)(Q)(CF)

[a]Spare parts costs consists of the costs for spare parts, maintenance labor, and maintenance maerials.

TABLE B-2.8 COST EQUATIONS FOR LIME SPRAY DRYING FGD SYSTEMS WITH PM REMOVAL

Routine Code: DS

Capital Costs:[b,c]

$TD = C1 + C2 + C3 + C4$

$C1 = 55{,}600\ (FLW)^{0.51}$

$C2 = 32{,}900\ (S2)^{0.40}$

$C3 = 18{,}400 + 8{,}260\ (FLW) + 6{,}420\ (FLW)^{0.50}$

$C4 = 256{,}320\ [W1 + W2]^{0.63}$

$W1 = Q * S/H * [0.626\ EFFSO2 - 79.9\ \ln\ (1-EFFSO2/100) - 10.1]$

$W2 = 3.96 \times 10^{-6} Q\ (UNCPM - CTRPM)$

$TK = 1.48\ TD + 110{,}400$ if $Q \leq 58.6$

$TK = 1.60\ TD$ if $Q > 58.6$

Annual Costs, $/Year

$DL = 8{,}760 * DLW * LF$

$SPRV = 1{,}314 * SPRV * LF$

$MANT = [0.08\ [55{,}600\ (FLW)^{0.51} + 32{,}900(S2)^{0.40}] + M1 + M2] * LF$

$M1 = 834\ FLW$

$M2 = MANT * (4.04\ FLW + 1{,}086)$

$ELEC = 8{,}760\ CF * ELEC\ [6.14\ (FLW)^{0.82}]$

$WTR = 8{,}760\ CF * WTR\ [0.144\ FLW]$

$SW = 8{,}760\ CF * SWD\ [W3 + W4]$

$W3 = (Q * S/H) * [569\ EFFSO2 - 72{,}700\ \ln\ (1-EFFSO2/100) - 9{,}230]$

$W4 = 3.6 \times 10^{-3} Q\ (UNCPM - CTRPM)$

$LIME = 8{,}760\ CF * ALIME * (-48{,}500) * Q * S/H * [\ln\ (1-EFFSO2/100) + 0.127]$

[a] FGD algorithms use metric units as noted in Table B-2.1

[b] $S1 = S * EFFSO2 * 100/H.$

[cd] $S2 = S1 * Q * 3.6.$

TABLE B-2.9 COST EQUATIONS FOR SODIUM SCRUBBING FGD SYSTEMS[a]

Routine Code: SOD[b,c]

Capital Costs:[d]

$TK_s = 39{,}900\ (FLW)^{0.585} + 1{,}370\ (S2)^{0.727}$

$TK_w = 26{,}500\ S_2^{\ 0.39}$

$TK = TK_s + TK_w$

Annual Costs:

DL = 1,100*DLW

SPRV = 165*SPRV

MANT = 0.08*TK

$ELEC_s$ = 8,760*CF*ELEC [3.61(FLW) - 2.15]

$ELEC_w$ = 8760*CF*ELEC [0.23(S2) + 1.32]

ELEC = $ELEC_s + ELEC_w$

WTR = 8760*CF*WTR [0.600(FLW) - 2.08] [0.527(S1) + 0.364]

SC = 8760*CF*SASH [3.33(S2) + 0.082]

LW = 8760*CF*LWD [0.0616(S2) + 0.298][e]

[a] All FGD algorithms are in metric units as noted in Table B-2.1

[b] $S1 = S*EFFSO_2*100/H$

[c] S2 = S1*Q*3.6

[d] The subscript "s" denotes scrubber costs and the subscript "w" denotes wastewater costs.

[e] This equation assumes that the wastewater stream has a total dissolved solids concentration (TDS) of 5%.

TABLE B-2.10 GENERAL DESIGN SPECIFICATIONS FOR FGD SYSTEM FOR SO_2 CONTROL

Control Device	Item	Specification
Sodium Scrubbing FGD (SO_2 removal only) (SOD)	Scrubber type Pressure drop[a] L/G Disposal method	Spray baffle 8 in. H_2O 40 gal/10^3 acf Oxidation and sewerage
Dry Scrubbing (spray drying, SO_2 and PM removal) (DS)	Material of construction	Carbon steel spray dryer and fabric filter (insulated)
	Reagent	Lime; with solids recycle at 2 kg recycle solids/kg fresh lime feed
	Fabric filter	Pulse jet; air-to-cloth ratio of 4 acfm/ft^2
	Pressure drop[a]	6 in. H_2O
	L/G	0.3 gal/acf
	Solids disposal	Trucked to off-site landfill

[a]All pressure drops refer to gas side pressure drop across entire control system.

TABLE B-3.1

ESTIMATED CAPITAL INVESTMENT FOR SELECTIVE CATALYTIC REDUCTION

Basis: 500-MW net grass-roots unit firing bituminous coal.
0.54 lb NO_2/million Btu before SCR treatment.

Capital Investment	Millions of 1979 Dollars
Plant facilities investment	
Reactors	9.10
Ducts, dampers, and expansion joints	1.98
Incremental FD fan cost	0.03
Incremental ID fan cost	0.91
Ammonia injection	1.26
Ammonia storage	0.81
General facilities	0.42
Paid-up royalties	0.11
Total plant facilities investment	14.62
Interest during construction*	2.15
Organization and start-up costs	0.73
Working capital	0.49
Initial catalyst	6.50
Total capital investment	24.49

*For nonregulated financing.

TABLE B-3.2

ESTIMATED OPERATING COSTS FOR SELECTIVE CATALYTIC REDUCTION

Basis: 500 MW net unit, 0.54 lb NO_2/million Btu before SCR treatment, 1.05 average stoichiometric ratio, 6,132 h/y.

First-Year Operating Costs (1979 dollars)	Million $/y
Raw materials	
Ammonia at $130/st	0.41
Catalyst	3.25
Maintenance materials	0.29
Total raw materials	3.95
Labor	
Operating labor	0.00
Operating labor supervision	0.00
Maintenance labor	0.22
Administrative and support labor	0.04
Payroll burden	0.09
Total labor	0.35
Electric power	0.49
Fixed costs	
G&A costs	0.29
Property taxes and insurance	0.37
Plant depreciation	0.58
Total fixed costs	1.24
Total operating costs	6.03

TABLE B-3.3

ESTIMATED CAPITAL INVESTMENT FOR
SELECTIVE NON-CATALYTIC REDUCTION

Basis: 500-MW net grass-roots unit firing bituminous coal.
0.54 lb NO_2/million Btu before SNR treatment.

Capital Investment	Millions of 1979 Dollars
Plant facilities investment	
Air compressor	2.08
Incremental ID fan cost	0.20
Ammonia storage	0.89
Double-grid injector system	1.68
General facilities	0.10
Paid-up royalties	0.05
Total plant facilities investment	5.00
Interest during construction*	0.73
Organization and start-up costs	0.25
Working capital	0.13
Total capital investment	6.11

*For nonregulated financing.

TABLE B-3.4

ESTIMATED OPERATING COSTS FOR SELECTIVE NON-CATALYTIC REDUCTION

Basis: 500-MW net unit, 0.54 lb NO_2/million Btu before SNR treatment, 1.2 average stoichiometric ratio, 6,132 h/y.

First-Year Operating Costs (1979 dollars)	Million $/y
Raw materials	
Ammonia at $130/st	0.48
Maintenance materials	0.10
Total raw materials	0.58
Labor	
Operating labor	0.00
Supervision	0.00
Maintenance labor	0.07
Administrative and support labor	0.02
Payroll burden	0.03
Total labor	0.12
Electric power	0.48
Fixed costs	
G&A costs	0.10
Property taxes and insurance	0.13
Plant depreciation	0.20
Total fixed costs	0.43
Total operating costs	1.61

Table B.3.5

COSTING ALGORITHM FOR SCR/SNCR

SCR

$$Capcst = 24.49E6 * (Q/1,800,000)^{.7}$$

$$Opcost = 6.03E6 * (Q/1,800,000)^{.7}$$

Totlab = Opcost * .35 / 6.03

Elpwr = Opcost * .49 / 6.03

Mtce = Opcost * .29 / 6.03

Ammcst = Opcost * .41 / 6.03

Fixcst = Opcost * 1.24 / 6.03

SNCR

$$Capcst = 6.11E6 * (Q/1,800,000)^{.7}$$

$$Cpcost = 1.61E6 * (Q/1,800,000)^{.7}$$

Totlab = Opcost * .12 / 1.61

Elpwr = Opcost * .48 / 1.61

Mtce = Opcost * .1 / 1.61

Ammcst = Opcost * .38 / 1.61

Fixcst = Opcost * .43 / 1.61

where Q = flow rate (acfm)

Table B.4.1

FUEL SWITCHING COST ALGORITHM

Operating cost of change

$$= Q(10^6 \text{BTU}) \times \text{Cost of new}(\$/10^6 \text{BTU}) - \text{Cost of old}(\$/10^6 \text{BTU})$$

Fuel Costs (obtained from suppliers)

Natural Gas	15 ¢/m^3	= 0.4248 ¢/ft^3
		= \$4.248/10^6 BTU
		= \$4.0304/10^9 J
Distillate	23.6 ¢/L	= \$6.868/10^6 BTU
		= \$6.516/10^9 J
Residual	31.75 ¢/L	= \$8.6573/10^6 BTU
		= \$8.214/10^9 J
Coal	\$55/T delivered	
		= \$1.89/10^6 BTU
		= \$1.793/10^9 J
Refuse	\$45/T	= \$1.546/10^6 BTU
		= \$1.467/10^9 J

TABLE B-4.2

Flue Gas Desulphurisation.

CAPITAL COSTS of EQUIPMENT.

```
Conv     =   8025 * S + 248600
Silo     =   4794 * S + 32816
Ball     =   16050 * S + 375000
PandML   =   11640 * S + 4000 * N + 30500
Stge     =   4588 * S + 16630 * SQRT(S) * N +234 * S^(2/3)
Abs      =   4.2824 * TotG
FandMA   =   0.53 * TotG
PandMA   =   0.232 * TotG + 24000 * N
Tank     =   0.089 * TotG + 108.6 * SQRT(N * TotG)
Soot     =   0.360 * TotG + 25100 * N
Duct     =   417.6 * SQRT(N * TotG) * DF
Valv     =   0.268 * TotG
Clar     =   37475 * SQRT(3.14 * S + AR)
VacF     =   23540 * S + 7496 * AR + 310400
TandM    =  236.48 * (3.14 * S + AR)^(2/3) + 1618.6 *
                                          (3.14 * S + AR)^(1/3)
Fixstr   =   1582 * S + 22000
PandMS   =   0.0184 * TotG + 3600 * S + 1146 * AR + 12000
Spond    =   64155 * SQRT((3.14 * S + AR) * CF * 100 + BLRY)
Mob      =   1883 * S + 22000
RR       =   30000 * N

A        =   Conv + Silo + Ball + PandML + Stge
B        =   Abs + FandMA + PandMA + Tank + Heat + Soot +
                                                  Duct + Valv
C        =   Clar + VacF + TandM + Fixstr + PandMS + Spond+
                                                  Mob + RR
```

OPERATING COSTS.

```
LS       =   18747 * S * LSCO * CF
FixCh    =   29200 * (3.14 * S + AR) * CF
Elec     =   0.04 * TotG * ELCO * CF
Water    =   0.049 * (0.129 * TotG + 2520 * S) * ELCO * CF
Direct   =   17520 * LBCO
Super    =   0.15 * Direct
Labmat   =   0.04 * GrandTotal
Supply   =   0.006 * GrandTotal
Plant    =   0.5 * (Direct + Super + Labmat + Supply)
Pay      =   0.2 * (Direct + Super)
Overhd   =   Plant + Pay
Labor    =   Direct + Super
Mntce    =   Labmat + Supply
Util     =   Elec + Water
Sludge   =   (3.14 * S + AR) * 29200 * TMGE * CF
Rawmat   =   LS + FixCh
ESO2     =   Sfctr * (100 - LSE) / 100
```

TABLE B-4.2 FLUE GAS DESULPHURIZATION (CONT'D)

Depr	=	GrandTotal / BLRY
Interim	=	0.0035 * GrandTotal
Taxes	=	0.04 * GrandTotal
Insur	=	0.003 * GrandTotal
CapCh	=	0.15 * GrandTotal
TotOp	=	Rawmat + Util + Labor + Mntce + Overhd
TotFix	=	Depr + Interim + Taxes + Insur + Capch

OVERALL CAPITAL COSTS.

Total	=	A + B = C
AdjDC	=	Esc * Total
IndCst	=	0.5125 * AdjDC
Cont	=	0.2 * (AdjDC + IndCst)
TOTANN	=	Totop + Totfix + Sludge

GrandTotal = 1.2 * (AdjDC + IndCst)

Table B.5.1.

FUEL CHARACTERISTICS

Fuel	Heat Cont. KJ/kg (BTU/lb)	S-Content %	Excess Air % normal	% LEA
Distillate oil	45,300 (19,500)	0.3	40	15
Residual oil	43,000 (18,500)	2.5	40	15
Coal	30,200 (13,000)	2.8	50	30
Wood waste (dry)	18,600 (8,000)	0.01	100	50
Municipal waste	11,600 (5,000)	0.1	100	50
Coke	33,700 (14,500)	5.0	10	-
Natural gas	37,200 KJ/m^3 (1,000 BTU/ft^3)	0.01	15	15

Table B.5.2

CHARACTERISTICS OF "UNCONVENTIONAL" FUELS

	Heat Content	SO_2 Content	Ref.
FCCU gas (no CO boiler)	-	1,000 (v/v) ppm	(1)
FCCU gas (regenerated) with CO boiler	-	1,350 (v/v) ppm	(1)
Black liquor	6,210 BTU/lb dry solids	-	(2)
Coke oven gas	550 BTU/ft^3 14,430 BTU/lb	250 v/v ppm	(2)
Refinery gas	1,200 BTU/ft^3	2% v/v	(2)
Propane	86,560 KJ/m^3 LHV 2,322 BTU/ft^3	0	(2)

Reference:

(1) Calvert & Englund (1984).

(2) Fryling (1967).

APPENDIX C

GLOSSARY

APPENDIX C: GLOSSARY

ACID GASES	gaseous emissions which are acidic or through chemical reactions, may produce acidic compounds, e.g. SO_2, HCl
ANNUALIZED COST	the yearly cost of a system including both direct and indirect operating costs and an amortized portion of the initial capital cost of the system
BAGHOUSE	a large chamber in which bag filters used to remove particulate from a gas stream are housed
BLAST FURNACE GAS - BF GAS	the gas product from iron ore smelting when hot air passes over coke in blast furnaces; contains carbon dioxide, carbon monoxide, hydrogen and nitrogen
CAPITAL RECOVERY FACTOR - CRF	a factor which when multiplied by the initial capital cost yields an annualized charge which "spreads" the cost of initial investment over the life of a project
COKE OVEN GAS - CO GAS	a gas produced during carbonization of coal to form coke
DRY SCRUBBING	a process in which SO_2 and other acid gases are removed from a gas stream by adsorption onto a sprayed dry or slurry sorbent, and subsequent removal of the sorbent bound SO_2 in a downstream particulate filter
FLUE GAS	gaseous products from a combustion process

FLUE GAS DESULPHURIZATION - FGD	a process by which sulphur is removed from a gas stream. The two basic methods of desulphurization are wet and dry scrubbing. Processes can be further classified as either saleable or throwaway depending upon whether sulphur compounds are recovered or discarded
FLUE GAS RECIRCULATION - FGR	a thermal NO_x reduction strategy whereby a portion of the flue gas is recirculated to the air inlet ports. The process is designed to reduce the oxygen concentration and temperature in the combustion zone
FLUIDIZED BED	an operation in which a bed of fine particles is held in suspension by an upward flowing gas stream
FLY ASH	fine noncombustible particulate matter found in combustion gases
FUEL NO_x	nitrogen dioxide produced from the reaction of fuel bound nitrogen and oxygen in the combustion gas
LIME	calcium oxide (CaO)
LIME INJECTION MODIFIED BURNER	a burner which has been redesigned to allow the direct injection of lime at the burner port of a coal fired boiler with the objective of providing a precombustion method of minimizing SO_2 generation
LIME SPRAY DRYER	a dry scrubbing process in which lime is used as the SO_2 removal agent
LIMESTONE	calcium carbonate ($CaCO_3$)
LOW NO_x BURNER	burners designed to control the air fuel and mix in the burner area with the objective of retarding formation of fuel NO_x

SELECTIVE CATALYTIC REDUCTION -SCR	a post-combustion process in which NO_x in a gas stream is converted to nitrogen by reduction with ammonia in the presence of a catalyst. The advantage over the SNCR process is a less restrictive range on operating temperatures.
SELECTIVE NON-CATALYTIC REDUCTION - SNCR	a post combustion process in which NO_x in a gas stream is converted to nitrogen by reduction with ammonia
STAGED COMBUSTION - SCA	a NO_x reduction strategy in which a portion of combustion air is injected at the burner with the remainder introduced downstream of the burner
THERMAL NO_x	nitrogen dioxide derived from the combination of atmospheric nitrogen and oxygen during combustion processes carried out at high flame temperatures
WET SCRUBBER	a device which uses a liquid to clean a gas. In this report the term refers to a device in which SO_2 is removed from a gas stream by absorption into an alkaline solution or slurry, typically of lime or limestone

APPENDIX D

EXAMPLES OF COMPUTER PRINTOUTS

APPENDIX D - LIST OF TABLES

D-1.1 Lime Spray Dryer
D-1.2 Limestone Flue Gas Desulphurization
D-1.3 Caustic Absorption
D-1.4 Fuel Switch to Natural Gas
D-2.1 Low Excess Air and Staged Combustion
D-2.2 Selective Non-Catalytic Reduction
D-2.3 Selective Catalytic Reduction

TABLE D-1.1: LIME SPRAY DRYER

VARIABLE SHEET

St Input	Name	Output	Unit	Comment
				Lime spray dryer with TSP removal
				File :- LSD-FF.TK
				13 sept. 1988
				Food & Bev. -Boilers
				Resid. Oil
2	Type		number	Type of fuel : Pulv. coal=1, other=2
				Program calculates in metric units
27.2	F			Flue gas rate Nm^3/min
	Flw	.74393162	m^3/sec	Flue gas flow rate
4.46	Q		1E6 BTU/h	Thermal input
19000	H		BTU/lb	Heating value of fuel
2.4	S		%	Sulphur content of fuel %
.03	A		%	Ash content of fuel
75	EffSO2		%	Efficiency of SO2 removal
.005	Ctrpm		ng/J	Controlled TSP emissions
1	Uncpm		ng/J	Uncontrolled TSP emissions
.85	CF		fraction	Capacity factor
	LF	1	number	Labour factor
14	AMlr		$1983	Maintenance labour rate $/man.hour
14	Sprv		$1983/hr	Labour supervision rate
12	Dlr		$1983/hr	Direct labour rate
.0165	Sud		$1983/kg	Solid waste disposal rate $/kg
.018	Alime		$1983/kg	Lime rate $ / kg
.02	Elec		$1983/kWh	Electricity rate
.06	Wtr		$1983/m^3	Water rate $/m^3
.1	Crf		$1983	Capital recovery factor
				Capital costs
	TD	229137.92	$1983	Total direct costs
	Ind	76302.927	$1983	Indirect costs
	Tdi	305440.85	$1983	Total direct and indirect costs
	TK	449524.12	$1983	Turnkey cost
	Cont	61088.169	$1983	Contingencies costs
	WC	41542.446	$1983	Working capital
				Operating and Maintenance costs
	Totop	236972.7	$1983	Total operating costs inc. Overheads
	Tdom	166169.78	$1983	Total direct Op. & Mtce costs
	SPSV	18396	$1983	Labour Supervision costs
	DL	105120	$1983	Direct labour costs
	Mant	27510.599	$1983	Maintenance labour costs
	ELEC	717.42825	$1983	Annual Electricity cost
	WTR	56.305506	$1983	Annual water cost
	SW	9292.5793	$1983	Solid waste disposal costs
	Lime	5076.8706	$1983	Annual lime supply costs
	OH	70802.916	$1983	Overhead
				Annualised costs.
	Total	304060.32	$1983	Total Annualised Costs
	Totann	304060.32	$1983	Total annualized charges
	CR	44952.412	$1983	Capital recovery cost

TABLE D-1.1: LIME SPRAY DRYER (CONT'D)

Wcc	4154.2446	$1983	Working capital charges
Misc	17980.965	$1983	Miscellaneous costs (taxes ins. etc.)
Tcc	67087.621	$1983	Total Capital charges
C1	47814.171	$1983	Intermediate value
C2	97736.865	$1983	Intermediate value
C3	30082.22	$1983	Intermediate value
C4	53504.564	$1983	Intermediate value
S2	15.210947		Intermediate value
W1	.08316158		Intermediate value
W2	1.7573E-5		Intermediate value
S1	.94736842		Intermediate value
M1	620.43897		Intermediate value
M2	15246.077		Intermediate value
W3	75.620154		Intermediate value
W4	.01597572		Intermediate value

TABLE D-1.2 LIMESTONE FLUE GAS DESULPHURIZATION

'HR$(27);H VARIABLE SHEET

St Input	Name	Output	Unit	Comment
				Flue Gas Desulphurisation - Limestone
				File :- FGDLS1.TK
				13 Sept 1988
				Food & Bev. Ind
				Boilers-Resid oil
95	LSE		%	Efficiency of L/S scrubber
	ESO2	.000015	lb/MBTU	Allowable SO2 rate - lb/10^6 BTU(39*S)
12.2	LBCO		$1988	Labour wages $/hr
18.75	LSCO		$1988	Limestone cost $ / ton
.5	TMGE		miles	Sludge trucking distance
1.9	Esc		number	Escalation factor to current date
49.5	ELCO		Mills	Electricity cost mills/ kWh
50	DF		ft	Estimated Duct run
20	BLRY		yr	Average boiler life remaining. =< 20
	Sfctr	.0003	ton/ton	SO2 emission rate from plant
	S	.00036765	ton/hr	SO2 removal rate - ton /hr
	AR	.14989095	ton/hr	Ash removal rate ton - /hr
	MCR	200	MW	Plant maximum continuous rating
	Gtot	960	acfm	Total actual gas flow from plant
	TotG	1586.087	cfm300	Plant flue gas rate - cfm at 300 F
	CF	96	number	Average capacity factor
1	N		number	Total number of trains needed
	OUTPUT		Units	Description
	GrandTo	7465551.5	$1988	Grand Total of costs
	TOTANN	2783090.4	$1988	Total Annual costs
	Total	2164869.2	$1980	Total system cost
	AdjDC	4113251.5	$1988	Adjusted direct cost (escalated to dat
	IndCst	2108041.4	$1988	Indirect cost (Int., Eng. spares etc.
	Cont	1244258.6	$1988	Contingency allowance
	Conv	248602.95	$1980	Conveyor cost
	Silo	32817.763	$1980	Storage Silo cost
	Ball	375005.9	$1980	Ball mill cost
	Stge	2.8876747	$1980	Storage tank cost
	PandML	30504.279	$1980	Pumps and motors cost for L-S preparat
	A	686933.78	$1980	Total L-S preparation cost
	Abs	6792.2588	$1980	Absorbers cost
	FandMA		$1980	Fans and motors cost for absorbers onl
	FandMV	1336.2783	$1980	Fans & motors cost for abs. with vent
	PandMA	367.97217	$1980	Pumps and motors cost
	Tank	141.16174	$1980	Tank cost
	Soot	571.78435	$1980	Sootblower cost
	Duct	0	$1980	Ducting cost
	Valv	425.0713	$1980	Valves cost

TABLE D-1.2 LIMESTONE FLUE GAS DESULPHURIZATION (CONT'D)

B	9634.5266	$1980	Total SO2 scrubbing cost
Clar	14564.492	$1980	Clarifiers cost
VacF	311532.24	$1980	Vacuum filters cost
TandM	929.07348	$1980	Tanks and mixers cost
Fixstr	10940.582	$1980	Fixation chemical storage cost
PandMS	12196.573	$1980	Sludge pumps and motors cost
Spond	1092533.7	$1980	Sludge pond cost
Mob	22000.692	$1980	Mobile equipment cost
RR	0	$1980	RR siding roads etc
C	1464697.3	$1980	Total sludge handling euipment cost
LS	124.06202	$1988	Total Limestone cost
FixCh	4234.1038	$1988	Fixation chemical cost
Elec	3316.3175	$1988	Total electricity cost
Water	47.857644	$1988	Total cost of water
ReHt	0	$1988	Flue gas reheating cost
Direct	213744	$1988	Direct labour cost
LabMat	298622.06	$1988	Labour and materials cost
Supply	44793.309	$1988	Cost of supplies
Plant	294610.49	$1988	Plant overheads
Super	32061.6	$1988	Supervisory costs
Pay	49161.12	$1988	Payroll overheads
TotOp	940714.92	$1988	Total operating cost
Util	3364.1751	$1988	Total utilities cost
Labor	245805.6	$1988	Total labour cost
Mntce	343415.37	$1988	Total maintenance cost
Overhd	343771.61	$1988	Total overhead cost
Depr	373277.58	$1988	Depreciation
Interim	26129.43	$1988	Interim replacement costs
Taxes	298622.06	$1988	Cost of taxes
Insur	22396.655	$1988	Cost of insurance
CapCh	1119832.7	$1988	Capital Charges
TotFix	1840258.5	$1988	Total fixed costs
Sludge	2117.0519	$1988	Sludge trucking costs

TABLE D-1.3: CAUSTIC ABSORPTION

VARIABLE SHEET

St	Input	Name	Output	Unit	Comment
					Caustic Absorption
					June 1 1988
					Paper & Allied - Process
					Lime Kiln
	468300	Qg		ft^3/hr	Gas rate acfm
	20	T		C	Temperature of gas
	100	ppm		ppm	ppm at inlet (base)
		ppmo	.1	ppm	ppm at outlet (top)
	99.9	Eff			
	5	NTU		number	Number of Transfer Units required
	29	MWg			Mol Wt of gas (air = 29)
	62.4	rol		lb/ft^3	Density of liquid
	1	ul		cpse	Liquid viscosity
	1	ulb		cpse	Liquid viscosity at base
	.075	rogb		lb/ft^3	Density of gas at base
	62.4	rolb		lb/ft^3	Density of liquid at base
	.0438504	ug		lb/ft.hr	Viscosity of gas(Air =.01812cpse @ 20C)
	160	Pf			Packing factor (= a/e^3)
	.236	Dg		cm^2/sec	Diffusivity in air (Assume .2)
	.00002	Dl		cm^2/sec	Diffusivity in H2O (assume = 2E-5)
	.75	s			Slope of equilibrium curve
	32.2	g		ft/sec^2	Acceleration due to gravity
	2080	F		hr/yr	Operating factor hr/yr
	.0203	Elcost		$1986	Unit cost of electricity
	.3741	water		$1986	Cost of water $/1000 gal
	12.23	labcst		$1986	Cost/hr of operator
	13.45	mtcecst		$1986	Cost/hr of maintenance
	.125	lab			Fraction of shift worked by operator
	.125	mtce			Fraction of shift worked by engineering
	1.9	Ohead			Factor for overheads
	.6	f			Factor to keep below flooding (.6 -.8)
	2402.5783	Qlb		lb/hr	Liquid flow at base of column
	133.47657	Lmo		lb.mol/hr	Liquid rate lb.mole/hr at base
	.25	Tc		in	Plate thickness
	43.24	rom		lb/ft^2	Function of weight /ft^2 of metal used for plate. 43.24 for 1/4 plate
	1	fm			Function of metal of column see below
	5224.4898	Head		in.water	Pump pressure: Nozzle press. + head
	300	l		ft	Length of piping
	2970	Ftcst		$1986	Cost / 100 ft of piping see below
	3.414	PI			PI
L	'Rasch_th	pack			Packing type
L	2.32	alph			Constant for packing type
L	.45	beta			Constant for packing type
L	.47	gamma			Constant for packing type
L	.00182	phi			Constant for packing
L	.46	eta			Constant for packing
L	139	ml			Constant for packing
L	.0072	n			Constant for packing

TABLE D-1.3: CAUSTIC ABSORPTION (CONT'D)

rog	.0808	lb/ft^3	Density of gas
Qgs	468300	ft^3/hr	Gas rate at standard temp and pressure
Qb	37823.98	lb/hr	Gas flow at base of column
Gmb	1304.2752	lb.mol/hr	Gas rate lb.mole/hr at base
Ql	25153.878	lb/hr	Liquid rate lb/hr
TU	4.5297663	ft	Overall gas transfer unit
Ht	22.648832	ft	Height of packed tower
Diam	5.8125863	ft	Diameter of column
DeltaPw	8.6616417	in.water	Column pressure drop (in.water)
DeltaP	45.014552	lb/ft^2	Column pressure drop (lb/ft^2)
Gm	1304.2752	mol/hr	Gas rate lb.mole/hr
Lm	1397.4377	mol/hr	Liquid rate lb.mole/hr
Q	37823.98	lb/hr	Gas rate lb/hr
A	.02393046		Intermediate factor for top of column
Gv	.43907905	lb/sec.ft	Superficial mass gas velocity
Gvf	.26344743	lb/sec.ft	Useful superficial gas velocity
S	26.522135	ft^2	Column cross sectional area at top
B	.00228572		Intermediate factor for base of column
Gvb	.42302659	lb/sec.ft	Superficial mass gas velocity at base
Sb	2.6293968	ft^2	Column cross sectional area at base
Gvfb	.25381596	lb/sec.ft	Useful superficial gas velocity at base
MolOb	.13044568		Moles at inlet (base)
MolOt	.00013045		Moles at outlet (top)
MRb	.00010001	ratio	Mol ratio SO2/air at inlet (base)
MRt	1.0001E-7	ratio	Mol ratio SO2/air at outlet (top)
TUg	3.635498	ft	Gas transfer units
G	1426.1288		Intermediate factor
Gb	14385.041		Intermediate factor (alternative)
L	948.41076		Intermediate factor
Lb	9566.4064		Intermediate factor (alternative)
TUl	1.2060977	ft	Liquid transfer coefficient
X	2.2995889		
Y	801.28205		
Cht	26.601978	ft	Overall column height
Basecst	29676.517	$1986	Basic cost of column shell + grids etc.
Shwt	5870.5005	lb	Weight of column
Catlp	11642.718	$1986	Cost of ladders and platforms
Packcst	32935.613	$1986	Cost of packing
Cst	33.7	$1986	Cost/ ft^3 of packing
Pipecst	8910	$1986	Cost of pipe work
Pumpcst	1697.1391	$1986	Cost of pump
Fancst	1795.68	$1986	Cost of fan
Pmpmtr	149.64	$1986	Cost of pump motor
Fanmtr	149.64	$1986	Cost of fan motor
Starter	448.92	$1986	Cost of motor starters
Tankvol	886.33545	ft^3	Vol. of recirc.tank (appr. 2.5hr hold up)
Metvol	11.538217	ft^3	Volume of metal in tank
Fanpwr	15.36931	HP	Fan HP needed
Pmppwr	8.230631	HP	Pump HP needed
Elcst	893.96173	$1986	Total cost of electricity
Watercs	2446.6171	$1986	Cost of water to scrubber
Labcst	6041.62	$1986	Cost of labour
Mtcecst	6644.3	$1986	Cost of mtce.
Cost	117991.51	$1986	Intermediate cost
Tankcst	8124.3431	$1986	Cost of recirculating tank

TABLE D-1.3: CAUSTIC ABSORPTION (CONT'D)

L	Totcost	131142.53 $1986	Total overall costs
	Totopcs	$1986	Total operating cost

Function of metal = fm

S/S 304	= 1.7
S/S 316	= 2.1
Monel 400	= 3.6
Inconel 600	= 3.9
Titanium	= 7.7

TABLE D-1.4: FUEL SWITCH TO NATURAL GAS

VARIABLE SHEET

St Input	Name	Output	Unit	Comment
				Low Excess air costs
				File :- LEAOIL.TK
				Fuel Switch Calculations
				09 Sept. 1988
				Food & Bev. - Boilers
				Resid oil
4.46	Q		MBTU/hr	Thermal input - 10^6 BTU/hr
23885	H		BTU/lb	Fuel heating value
1	XS		number	Enter 0 if not LEA, 1 for LEA
.96	CF		fraction	Capacity factor
2	Fuel			For coal = 1, for oil or gas = 2.
4.187	FC		$/MBTU	Fuel cost $/MBTU in $1981
0	N2		%	Nitrogen content of fuel
40	Uncea		%	Uncontrolled excess air - see below
15	Ctrcea		%	Controlled excess air - see below
9393	Ffac		dscf/MBTU	Fuel factor
				LEA = 15% excess air (oil or gas)
				LEA = 35% excess air (stoker)
				LEA = 30% excess air (pulverised)
				Non-LEA = 40% excess air (oil or gas)
				Non-LEA = 50% excess air (coal)
				Ffac :- Natural Gas = 9000
				Ffac :- Oil = 9393
				Ffac :- Coal = 9260
	PRCT	-18.7	%	percent flame extension due to staging
	FLW	1271.6182	acfm	Flue gas flow rate for natural gas
	FLWO	1635.3695	acfm	Fluegas flowrate for oil
	FLWC	2166.1572	acfm	Fluegas flowrate for stoker boiler
	FLWP	2059.1428	acfm	Flue gas flow rate for pulverised coal
	FLWFB	1328.2772	acfm	Flue gas flow rate for FBC
	Equip	11714.901	$1987	Equipment cost
	Inst	2665.7624	$1987	Installation cost
	Ind	2665.7624	$1987	Indirect cost
	SP	852.32127	$1987	Spare parts costs
	TK	17046.425	$1987	Turnkey cost
				LOW EXCESS AIR
	FUEL	-5093.763	$1987	Annual fuel cost
				STAGED COMBUSTION (Oil)
	TKSC	-115153.2	$1987	Turnkey cost for staged combustion
	ELEC	960.79104	$1987	Electricity cost per annum
				"STAGED COMBUSTION (Pulverised coal)
	Equipp	29237.78	$1987	Equipment cost (pulverised coal)
	Instp	4988.72	$1987	Installation cost (pulverised coal)

TABLE D-1.4: FUEL SWITCH TO NATURAL GAS (CONT'D)

Indp	4988.72	$1987	Indirect costs (pulverised coal)
SPP	852.32127	$1987	Spare parts (pulverised coal)
ELECP	989.0496	$1987	Electricity cost (pulverised coal)
FuelP	863.72571	$1987	Fuel costs (pulverised coal)
FUELSCO	863.72571	$1987	Fuel costs staged combustion

TABLE D-2.1: LOW EXCESS AIR AND STAGED COMBUSTION

VARIABLE SHEET

St	Input	Name	Output	Unit	Comment
					Low Excess air costs
					File :- LEAOIL.TK
					09 Sept. 1988
					Metal Fab- Boilers
					Resid. oil
	81.08	Q		MBTU/hr	Thermal input - 10^6 BTU/hr
	19000	H		BTU/lb	Fuel heating value
	1	XS		number	Enter 0 if not LEA. 1 for LEA
	.96	CF		fraction	Capacity factor
	2	Fuel			For coal = 1. for oil or gas = 2.
	7.703	FC		$/MBTU	Fuel cost $/MBTU in $1981
	.7	N2		%	Nitrogen content of fuel
	40	Uncea		%	Uncontrolled excess air - see below
	15	Ctrcea		%	Controlled excess air - see below
	9393	Ffac		dscf/MBTU	Fuel factor
					LEA = 15% excess air (oil or gas)
					LEA = 35% excess air (stoker)
					LEA = 30% excess air (pulverised)
					Non-LEA = 40% excess air (oil or gas)
					Non-LEA = 50% excess air (coal)
					Ffac :- Natural Gas = 9000
					Ffac :- Oil = 9393
					Ffac :- Coal = 9260
		PRCT	30	%	percent flame extension due to staging
		FLW	29060.779	acfm	Flue gas flow rate for natural gas
		FLWO	24927.493	acfm	Fluegas flowrate for oil
		FLWC	33261.378	acfm	Fluegas flowrate for stoker boiler
		FLWP	31789.101	acfm	Flue gas flow rate for pulverised coal
		FLWFB	24147.246	acfm	Flue gas flow rate for FBC
		Equip	17004.439	$1987	Equipment cost
		Inst	4582.3351	$1987	Installation cost
		Ind	4582.3351	$1987	Indirect cost
		SP	1308.4555	$1987	Spare parts costs
		TK	26169.109	$1987	Turnkey cost
					LOW EXCESS AIR
		FUEL	-170362.7	$1987	Annual fuel cost
					STAGED COMBUSTION (OIl)
		TKSC	455788.61	$1987	Turnkey cost for staged combustion
		ELEC	17466.578	$1987	Electricity cost per annum
					"STAGED COMBUSTION (Pulverised coal)
		Equipp	40194.44	$1987	Equipment cost (pulverised coal)
		Instp	15102.56	$1987	Installation cost (pulverised coal)
		Indp	15102.56	$1987	Indirect costs (pulverised coal)

TABLE D-2.1: LOW EXCESS AIR AND STAGED COMBUSTION (CONT'D)

SPP	1308.4555	$1987	Spare parts (pulverised coal)
ELECP	17980.301	$1987	Electricity cost (pulverised coal)
FuelP	28887.614	$1987	Fuel costs (pulverised coal)
FUELSCO	28887.614	$1987	Fuel costs staged combustion

TABLE D-2.2: SELECTIVE NON-CATALYTIC REDUCTION

VARIABLE SHEET

St Input	Name	Output	Unit	Comment
				NOx Removal - SNCR. 09 Sept. 1988 Metal & Fab- Boilers Resid oil
16270	Qn		Ncfm	Flue gas volume Ncfm
175	T		C	Flue gas temperature
	Q	26699.487	acfm	Flue gas flow rate - acfm
	Capcst	705220.91	$1987	Capital cost
	Opcost	185827.44	$1987	Total Operating costs
	Totlab	13850.493	$1987	Labour costs
	Elpwr	55401.97	$1987	Electricity cost
	Mtce	11542.077	$1987	Maintenance cost
	Ammcst	43859.893	$1987	Ammonia cost
	Fixcst	49630.932	$1987	Fixed operating cost
273	n		K	Normal Temperature

TABLE D-2.3: SELECTIVE CATALYTIC REDUCTION

VARIABLE SHEET

St	Input	Name	Output	Unit	Comment
					NOx Removal - SCR
					09 Sept 1988
					Metal Fab- boilers
					Resid oil
	16270	Qn		Ncfm	Flue gas volume Ncfm
	175	T		C	Flue gas temperature
		Q	15023.59	acfm	Flue gas flow rate - acfm
		Capcst	1890002.2	$1987	Capital cost
		Opcost	465361.92	$1987	Total Operating costs
		Totlab	27011.057	$1987	Labour costs
		Elpwr	37815.479	$1987	Electricity cost
		Mtce	22380.59	$1987	Maintenance cost
		Ammcst	31641.523	$1987	Ammonia cost
		Fixcst	95696.315	$1987	Fixed operating cost
	273	n		K	Normal temperature

COUNTDOWN ACID RAIN

FUTURE ABATEMENT STRATEGIES

PHASE III

"Abatement Strategy Assessment"

Prepared by:

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DISCLAIMER

The conclusions, opinions and recommendations expressed in this report are those of the consultant and do not necessarily represent the views of the Ontario Ministry of the Environment. In addition, the consultant is solely responsible for the accuracy of data and estimates presented in this report.

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FORWARD

This report presents a study of SO_2 and NO_x emission sources in Ontario and proposed emission control strategies to achieve Ontario's commitment for SO_2 and NO_x reductions after 1993. The report consists of a summary document supported by three appendices.

Summary	The summary document describes the findings of 2 phases of the study and draws conclusions on abatement strategies.
Appendix 1	The Phase I Report sets out a 1985 base year emission inventory for SO_2 and NO_x examines past trends, and outlines five basic future scenarios.
Appendix 2	The Phase II Report identifies the costs of reducing SO_2 and NO_x emissions using alternative emission targets identified in the Phase I Report.
Appendix 3	The Phase III Report develops alternative cost-effectiveness abatement strategies that achieve pre-specified aggregate emission targets. The strategies are based on control technologies, described in Phase II, that are presently considered suitable for SO_2 and NO_x emission control. The computer model developed for the foregoing work is described.
This Document	This document describes Phase III, Appendix 3.

PHASE III
EXECUTIVE SUMMARY

The Ministry of the Environment has commissioned a study entitled "Countdown Acid Rain Future Abatement Strategies". The first two Phases of this study produced an updated inventory of SO_2 and NO_x emissions for Ontario and information on abatement technologies describing the removal efficiencies and associated costs of alternative control technologies for major point sources and for industrial sectors which are also significant in aggregate. The third Phase, which is the subject of this report, incorporates information from the first two phases into an analytic framework for developing and evaluating alternative acid rain abatement strategies.

Emission controls for the following sources were used in the analysis:

SECTOR or SOURCE	INCLUDED IN SO_2 SCENARIOS	INCLUDED IN NO_x SCENARIOS
Primary Metals	Yes	No
Food and Beverages	Yes	Yes
Rubber and Plastics	No	Yes
Leather, Textile and Clothing	Yes	Yes
Paper and Allied Products	Yes	Yes
Metal Fabrication Machinery Industries	Yes	Yes
Transportation Equipment Industries	Yes	Yes
Non-Metallic Mineral Products	Yes	Yes
Chemical and Petroleum Products	Yes	Yes
Other Groups	Yes	Yes
INCO	Yes	No
Ontario Hydro	Yes	Yes
Falconbridge	Yes	No
Algoma	Yes	No
Mobile Sources	No	Yes

Note: No_x emissions for Falconbridge and Algoma were judged not to be significant for purposes of this study.

These data were incorporated into a computer spreadsheet model designed to identify the least cost combination of control options that will achieve a pre-specified level of Provincial emission reduction. Only existing Ontario sources are considered in the model and control costs for these are generic in nature. Abatement costs and emission reduction levels for alternative emission control technologies are defined for entire sectors in the model rather than for individual plants in each sector. Consequently, abatement strategies developed with the model prescribe emission reduction requirements for this entire sector rather than for individual emitters.

The starting point in formulating alternative abatement strategies was assumed to be the level of provincial emissions that will remain in 1994 after the implementation of emission controls mandated by Regulations covering the major point sources: INCO, Ontario Hydro, Algoma and Falconbridge.

Only two or three discrete control technologies were considered for each major point source or sector, and no interpolations of the data were made to allow for emission control reduction levels falling between the levels corresponding to these technologies. Due to the discrete nature of the emission control data, aggregate emission reduction levels developed with the model may exceed or be lower than target reduction levels for specific scenarios.

Summary results from the analysis are provided in Tables 1 and 2. Emission control costs and resulting emission reductions in these tables represent province-wide aggregates covering all controllable sources. Emission control cost estimates in these tables do not include those costs that must be incurred to satisfy the 1994 emission targets mandated by the regulations for INCO, Hydro, Falconbridge and Algoma Steel at Wawa.

NO_x emissions are dominated by mobile source emissions which are now subject to Federal regulation. Federally mandated controls for new vehicles can readily make up for any failure on the part of Ontario Hydro to achieve its 1994 Regulation levels for NO_x. The maximum potential NO_x emission reduction is 267,000 tonnes at a present value cost of $6,476 M. Mobile source controls account for 64% of this reduction.

SO_2 emissions on the other hand are dominated by the large point sources. For example, the scenario involving a failure by INCO to meet 1994 regulated SO_2 targets causes all other sources to be pushed to maximum control levels. Target emission reductions for this scenario exceed the achievable reductions by 118,000 tonnes.

Abatement costs rise rapidly with the degree of emission reduction. Moving from the 10% reduction level to the 50% reduction level for either SO_2 or NO_x (a five-fold increase), causes costs in both cases to increase thirty-fold in present value terms.

It can be concluded that emission reductions at INCO are critical if Ontario is to meet its SO_2 emission reduction commitments at a reasonable cost. If INCO does not reduce its emissions to 1994 target levels, then the aggregate provincial targets may not be achievable even if all other sources implement their maximum SO_2 control levels.

TABLE 1: SUMMARY OF SO_2 ABATEMENT STRATEGIES

ABATEMENT STRATEGY SCENARIO [1]	EMISSION CONTROL COSTS (M 1987 $) OPERATING	CAPITAL	PRESENT VALUE	EMISSION CONTROL (1000's TONNES/YR) TARGET REDUCTION [2]	MODELED REDUCTION [3]
10% Reduction	$ 12	$ 43	$ 159	90	103
30% Reduction	$ 63	$ 299	$ 887	271	278
50% Reduction	$342	$2,146	$5,338	450	445
Reduction to 1994 target level, INCO remains at 1985 emission levels	$307	$2,062	$4,933	430	312 [4]
Reduction to 1994 target level, INCO achieves 1/2 of its 1994 target reduction	$ 57	$ 390	$ 921	215	208
Reduction to 1994 target level, Hydro remains at 1985 emission levels	$ 26	$ 76	$ 321	162	156
Reduction to 1994 target level, Hydro achieves 1/2 of its 1994 target reduction	$ 6	$ 26	$ 78	81	77

NOTES:

1. Percent reduction relates to 1994 base case emissions after Regulations are met, which are 900,885 tonnes/yr. This figure exceeds the 1994 MOE objective (885,000 tonnes) because it assumes that Algoma and Falconbridge will increase emissions to maximum acceptable levels.

2. "Target Reduction" is the percent reduction referenced in column 1 or the shortfall arising as a result of any failure to meet 1994 Regulations.

3. Discrepancies between target and modeled emission reduction levels are due to discrete nature of the control options.

4. All sectors are at maximum emission control levels.

TABLE 2: SUMMARY OF NO_x ABATEMENT STRATEGIES

ABATEMENT STRATEGY SCENARIO [1]	EMISSION CONTROL COSTS (M 1987 $) OPERATING	CAPITAL	PRESENT VALUE	EMISSION CONTROL (1000's TONNES/YR) TARGET REDUCTION [2]	MODELED REDUCTION [3]
10% Reduction	$ 15	$ 77	$ 216	58	36
30% Reduction	$ 15	$1,051	$1,190	173	189
50% Reduction	$347	$3,236	$6,476	289	267 [4]
Reduction to 1994 target level with Hydro remaining at 1985 emission levels	$ 0 [6]	$ 974 [6]	$ 974	33	149 [5]

NOTES:

1. Percent reduction relates to base case emissions after Regulations are met, which are 578,135 tonnes/yr.

2. "Target Reduction" is the percent reduction referenced in column 1 or the shortfall arising as a result of any failure to meet 1994 Regulations.

3. Discrepancies between target and modeled emission reduction levels are due to discrete nature of the control options.

4. All sectors are at maximum emission control levels.

5. A reduction of 149,000 tonnes NO_x is achieved by means of Federally mandated controls on mobile sources. Only a portion of these are actually required to meet the 1994 Provincial emission reduction target for NO_x.

6. Costs are for 3-way catalytic converters on mobile sources. Only capital cost data were provided for this option (See Scenario 12 in Table 4.8 and Appendix D of this report).

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The project study team included:

M. Fortin	Ecologistics Limited
E.A. McBean	University of Waterloo
S. Tang	Ecologistics Limited

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1.0 INTRODUCTION

1.1 Background

Extensive information has been developed regarding the causes and effects of acid rain and the technologies available for reducing the emissions responsible for acid rain. However, this knowledge by itself does not solve the policy-maker's problem of determining the emission reduction levels required at individual sources to achieve overall environmental objectives.

Many approaches exist to determine alternative abatement strategies for acid rain, including, an emission-driven approach, a deposition-targeted approach and a cost-effective or least-cost targeted approach [McBean et al, 1985]. The latter two approaches relate the impact of controls at emissions sources to sensitive receptor areas. A linear programming screening model was developed by McBean et al [1985] that utilized a source/receptor linkage. It reduces the total number of abatement scenarios to be considered by identifying those strategies which are both efficient in terms of minimizing control costs, and effective in terms of achieving the desired deposition objectives.

This screening model provided valuable technical support in early discussions of national and trans-national abatement requirements by addressing the problem at a continental scale. Its particular strength lay in its ability to evaluate emission control requirements at the provincial/state level and at the national level.

The broad scale of this model however, had two major implications: first, only major sources could readily be accommodated within the model structure, and second, detailed information was required related to source inventories, abatement cost functions and long-range transport relationships. As the provinces' acid-rain control policy evolves, it must focus increasingly, and in more detail, on the issues of how and

where to control emissions. A larger number of provincial sources must be considered and greater attention must be paid to the cost implications of alternative abatement strategies.

In keeping with these changing policy interests, the analytic approach employed must also change. To this end, the Ministry of the Environment has commissioned a study entitled "Countdown Acid Rain Future Abatement Strategies". The first two Phases of this study produced an updated inventory of emission control data describing the removal efficiencies and associated costs of alternative control technologies for major point sources and for industrial sectors which are also significant in aggregate. A parallel study by MacLaren Plansearch Ltd. (1988) produced NO_x emission reduction and control cost data for mobile sources. The third Phase, which is the subject of this report, incorporates this data into an analytic framework for developing and evaluating alternative acid rain abatement strategies.

1.2 Objectives of the Study

The objective of this third phase of the study was to develop alternative, cost-effective abatement strategies that achieve pre-specified aggregate emission targets. This objective entailed three primary tasks:

1) development of a simple and efficient approach to the analysis of cost-effective acid-rain abatement strategies;
2) implementation of the approach as a computer model;
3) application of the model to a set of predetermined policy scenarios.

1.3 Scope

A number of features defined the scope of this study, namely:

- only Ontario sources were to be considered;

- the analysis addressed both SO_2 and NO_x emission reduction targets;
- the impact of emission reductions on receptor deposition were not addressed;
- emission reductions considered here move the Province beyond those emission reductions already required for 1994 by Regulations imposed on Ontario Hydro, INCO, Falconbridge and Algoma;
- only existing sources were to be considered (though the approach should provide the opportunity to add new sources in subsequent analyses);
- emission controls are assumed to be implemented by 1994;
- emission control cost data of a generic nature were used, and, with the exception of those four major sources cited above, emission sources were aggregated by sector.

1.4 Product

The principal end product of this phase of the "Countdown" study is a set of abatement scenarios that evaluate the implication of future uncertainty in the emission control performance of the four regulated sources. In particular, an evaluation is made of the SO_2 and NO_x emission controls required to move beyond the 1994 Regulation levels and of how these requirements are affected if the 1994 Regulation levels are not achieved.

2.0 METHODOLOGY

2.1 Overview

Cost-effectiveness provides the underlying approach to strategy development in this study. Each abatement strategy is based on a scenario comprising:

- an emission reduction target,
- assumptions regarding the interest rate, the planning horizon and starting or base case emission levels,
- constraints requiring that certain technologies or sectors be forced into the strategy or conversely be left out.

A cost-effective abatement strategy is defined as one that conforms to the requirements of a scenario while minimizing the total abatement cost to the polluters.

Various approaches can be used to identify cost-effective abatement strategies from among the complete set of strategies that would fulfill the requirements of a scenario. The simplest involves generating every conceivable strategy and then picking the least expensive one. This may be feasible in very limited cases involving only a few control options, but is not otherwise practical. At the other end of the spectrum, there are sophisticated decision algorithms such as linear programming which go further than required for this study.

The approach that was most reasonable, given the nature of the study entailed an analysis of the incremental or marginal costs associated with the alternative control technologies available at each source or in each sector. In essence, this approach simply requires that technologies be sorted in order of increasing marginal cost; then, for any given scenario, options must be selected progressively from this list until the aggregate emission target is achieved.

This chapter goes on to describe how the marginal cost approach is applied, moving progressively through the topics of total cost estimation, abatement cost function development, strategy development and the generation of scenarios. A numerical example is provided in the last section to further clarify the discussion. The computer model developed to implement this approach is documented in Appendix C.

2.2 Total Costs

Abatement costs include both the capital costs associated with installing control equipment and the recurrent annual operating costs for running and maintaining that equipment. In this application, the cost data correspond to distinct and mutually exclusive control options. Where two discrete technologies, such as a fuel adjustment and a flue gas scrubbing system can be used separately or in combination, the combination is therefore identified as a third control option.

In order to place all cost data - both near-term capital expenditures and future operating costs - on the same footing for purposes of comparison it is necessary to express these in terms of dollar values in a single reference year. A present value calculation is used to do this. This calculation, in effect, expresses all capital and future operating costs in terms of a capital fund that, if invested at prevailing market interest rates in the first year of implementation of a control technology, would completely finance that technology over the full planning horizon.*

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* By assuming a market interest rate measured net of inflation, we are measuring the cost of capital funds in the private sector. This cost may vary from the social cost of capital funds due to taxation and other factors that affect the market for capital funds. The analytic approach described below enables the user to select market or social values for the interest rate.

Present values are calculated using the following equation:

$$PV = CC + OC_1(1 + R)^{-1} + OC_2(1 + R)^{-2} + \ldots + OC_n(1 + R)^{-n} \quad \ldots(1)$$

where PV = Present Value of Total Costs;
CC = Initial Capital Cost;
OC_t = Operating Cost in year t;
R = Real Interest Rate;
n = time horizon in years.

Market interest rates incorporate a factor accounting for the impact of inflation on the value of savings.

The real interest rate is measured net of this inflation factor and is calculated as follows:

$$R = ((1 + i)/(1 + I))-1 \quad \ldots(2)$$

where i = Nominal or Market Interest Rate;
I = Inflation Rate.

2.3 Abatement Cost Functions

Once abatement cost data are expressed in present value form, it is necessary to develop an abatement cost function for each discrete source or sector. An abatement cost function describes the relationship between total cost and removal efficiency over a range of removal efficiencies. The feature that distinguishes the abatement cost function from a simple schedule of all available control technologies is that any inefficient control technologies are omitted from the abatement cost function. These

are technologies that are technically inferior because they offer a lower removal efficiency at a higher total cost than alternative efficient technologies (control technology 1 in Figure 2.1). Thus, when total costs are plotted against removal efficiencies for all control technologies for a given source or sector, the abatement cost function comprises the lower envelope of points representing the least cost alternatives - shown as control technologies 2, 3, and 4 in Figure 2.1.

The marginal cost for a control technology on the abatement cost function is defined as the increase in cost divided by the increase in emission removals with increases measured relative to the next lower option. In other words, it is the slope of the line segment joining a data point to the next lower data point, or conversely it is the unit cost or average cost per tonne removed defined over that line segment (see Figure 2.1). In calculating marginal costs, the emission reductions must be expressed in present value terms in order to be commensurate with the present value cost data. To do otherwise (i.e. to divide by the simple sum of emission removals over time) would entail mixing values with different time scales and would produce meaningless unit cost data.

The total cost will always increase as one moves up an abatement cost function, but the marginal cost may increase or decrease depending on whether the slope of the function is increasing (a convex function) or decreasing (a concave function). Typically, however, marginal costs increase as removal efficiency increases for a given source since it is usually more difficult, and consequently more costly, to remove increasing amounts of a contaminant from an emission stream.

For reasons that will be developed in the next section, the use of an algorithm based on marginal costs necessitates that all abatement cost functions be either linear or convex. Thus, where a section of an abatement cost function was found to be concave, the offending data point was dropped and the line segment then connected to the next data point in the function as with control technology 3 in Figure 2.2.

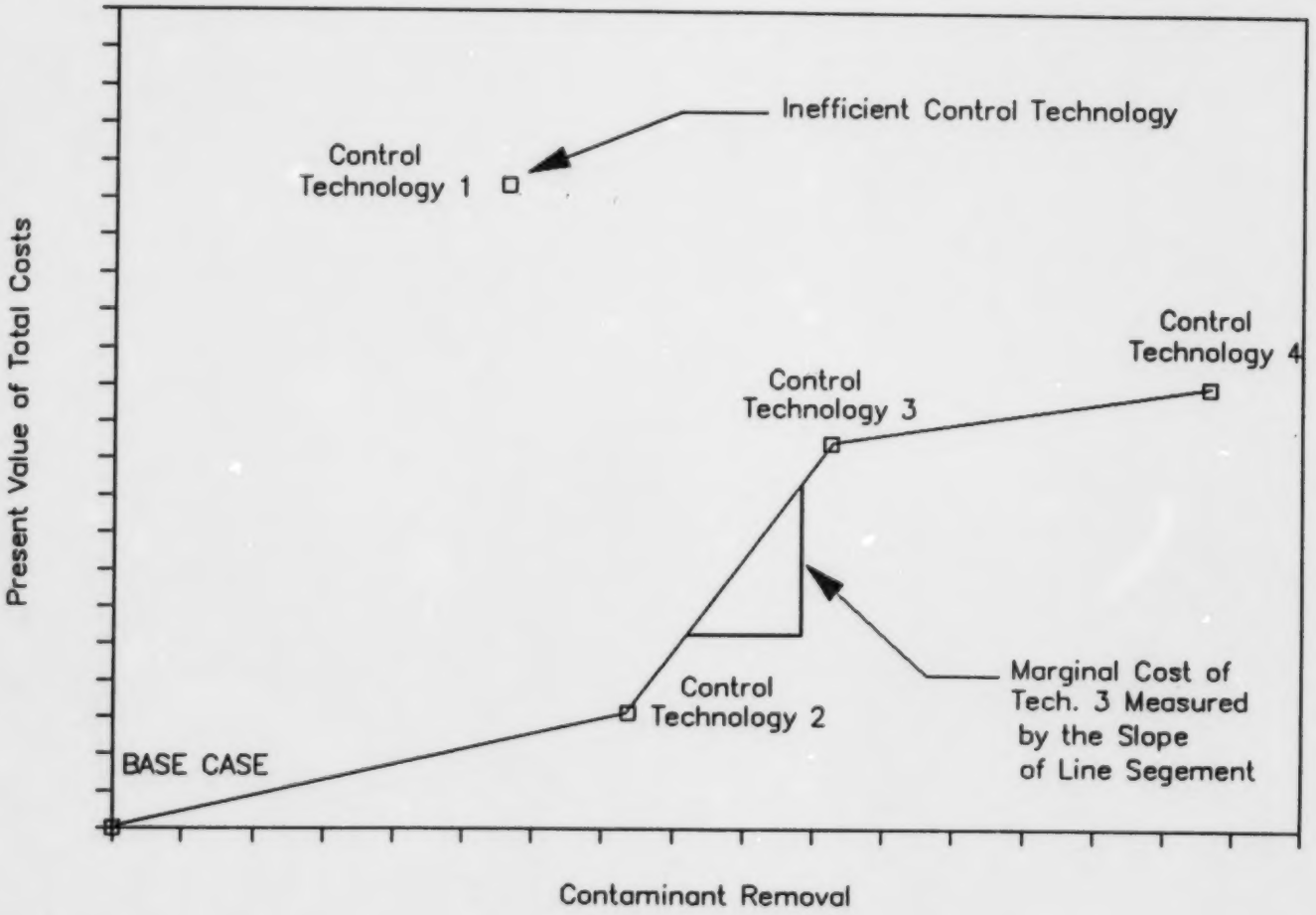
Inefficient Control Technology
Control Technology 1
Control Technology 4
Control Technology 3
Control Technology 2
Marginal Cost of Tech. 3 Measured by the Slope of Line Segement
BASE CASE
Present Value of Total Costs
Contaminant Removal

Figure 2.1 Development of an Abatement Cost Curve

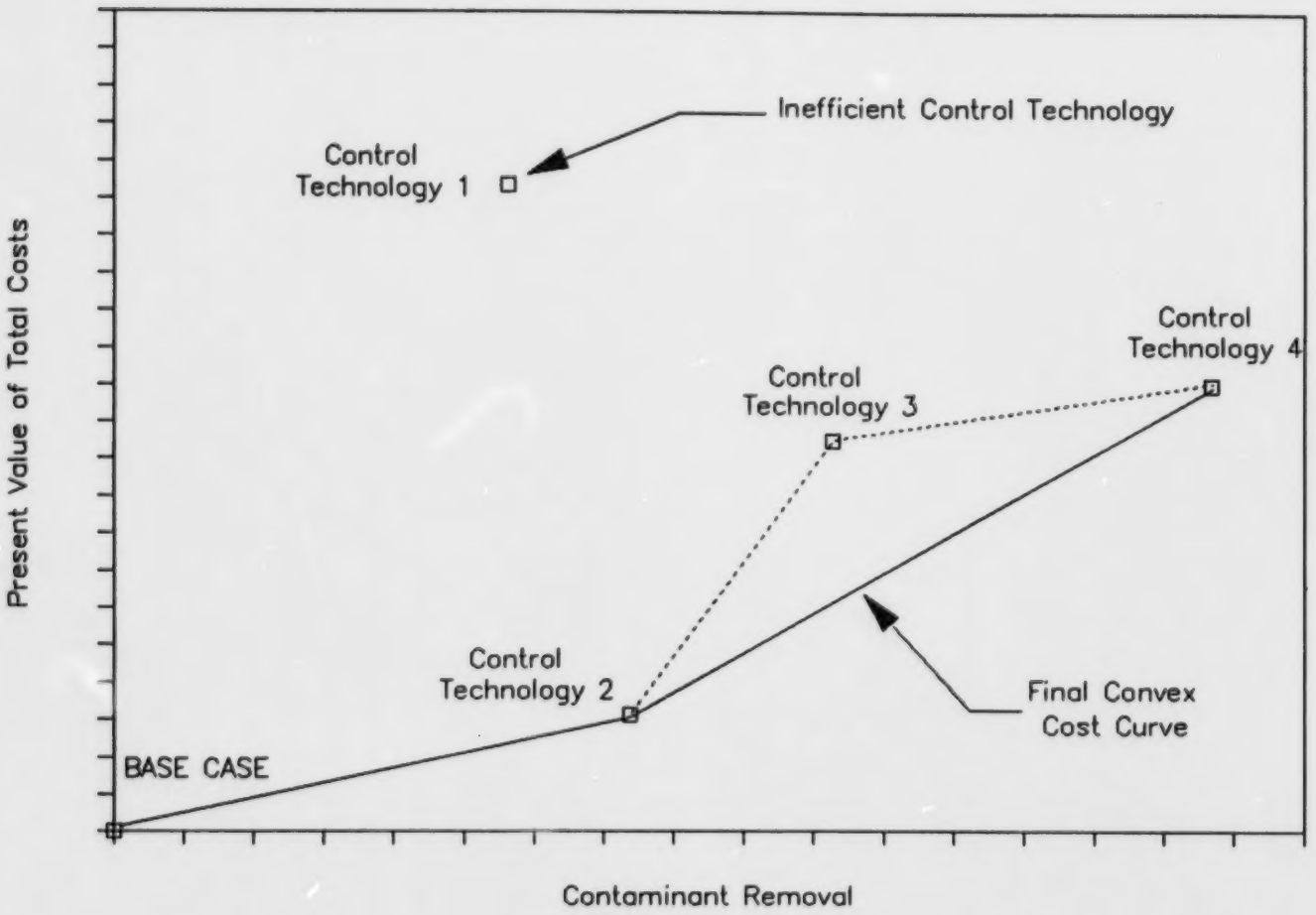

Figure 2.2 Development of a Convex Abatement Cost Curve

2.4 Strategy Development

The abatement cost functions are the primary data inputs used in developing an abatement strategy. The other prerequisite is the scenario which stipulates conditions to be satisfied by the strategy and assumptions that modify the input data (see Section 2.1).

The next step in the analysis essentially involves the development of an aggregate abatement cost function for the entire province comprising all of the individual source and sector control options sorted in order of increasing marginal cost. Once sorted, the aggregate function is derived as a schedule or plot of cumulative control option costs against cumulative emission reductions. The values to be cumulated are the incremental costs and incremental emission reductions used to define marginal costs for each control option.

Since control options are first sorted based on increasing marginal cost, the slope of the aggregate function must increase as total emission reduction increases. The function is therefore also convex.

The abatement strategy is determined by selecting the discrete data point on the aggregate abatement cost function that most closely matches the target emission reduction for the scenario in question. (Since only discrete control options are considered here, a continuous interpolation between data points to provide an exact match to the target is not made.)

All control options represented by data points lying between a zero reduction level and the selected control option on the aggregate function must then be evaluated in order to determine the emission reduction level required for each source or sector. Any source or sector not represented in this set of control options is obviously excluded from the strategy.

The analysis of included sources or sectors relies critically on the convexity of their individual abatement cost functions. Due to this convexity, data points from each of these individual curves will appear in

the aggregate abatement cost function in the same order as is found in the individual curve (although individual data points may be separated by data points drawn from other sources or sectors). This is the case because the aggregate curve is also convex.

Thus, if only one point is found for a source or sector in the selected set of data points, it must be the first or lowest level control option for that source or sector. If two or more data points for a single source or sector occur in the selected set, however, these will represent consecutive control options starting with the first. Since these are mutually exclusive (see Section 2.3) it is the last or highest level option that represents the required removal level for that source or sector (see Figure 2.3).

2.5 Generation of Scenarios

As noted in Section 2.1, factors that define a scenario are:

- the aggregate emission reduction target,
- assumptions regarding interest and inflation rates, the planning horizon and the base case emissions, and
- constraints related to controls for specific sources or sectors.

When the aggregate emission reduction target is increased, new emission controls will be required. Depending on the size of the increase, changes in removal levels may be required for all sources and sectors or for only some of them. If the latter is the case, then the control technologies and consequently the marginal costs will change only for those sources and sectors for which higher removal levels are prescribed in the new scenario.

When financial assumptions or base case emissions are changed, the costs for individual control options change, in the former case due to a change in the present value calculation and in the latter case as a result of a

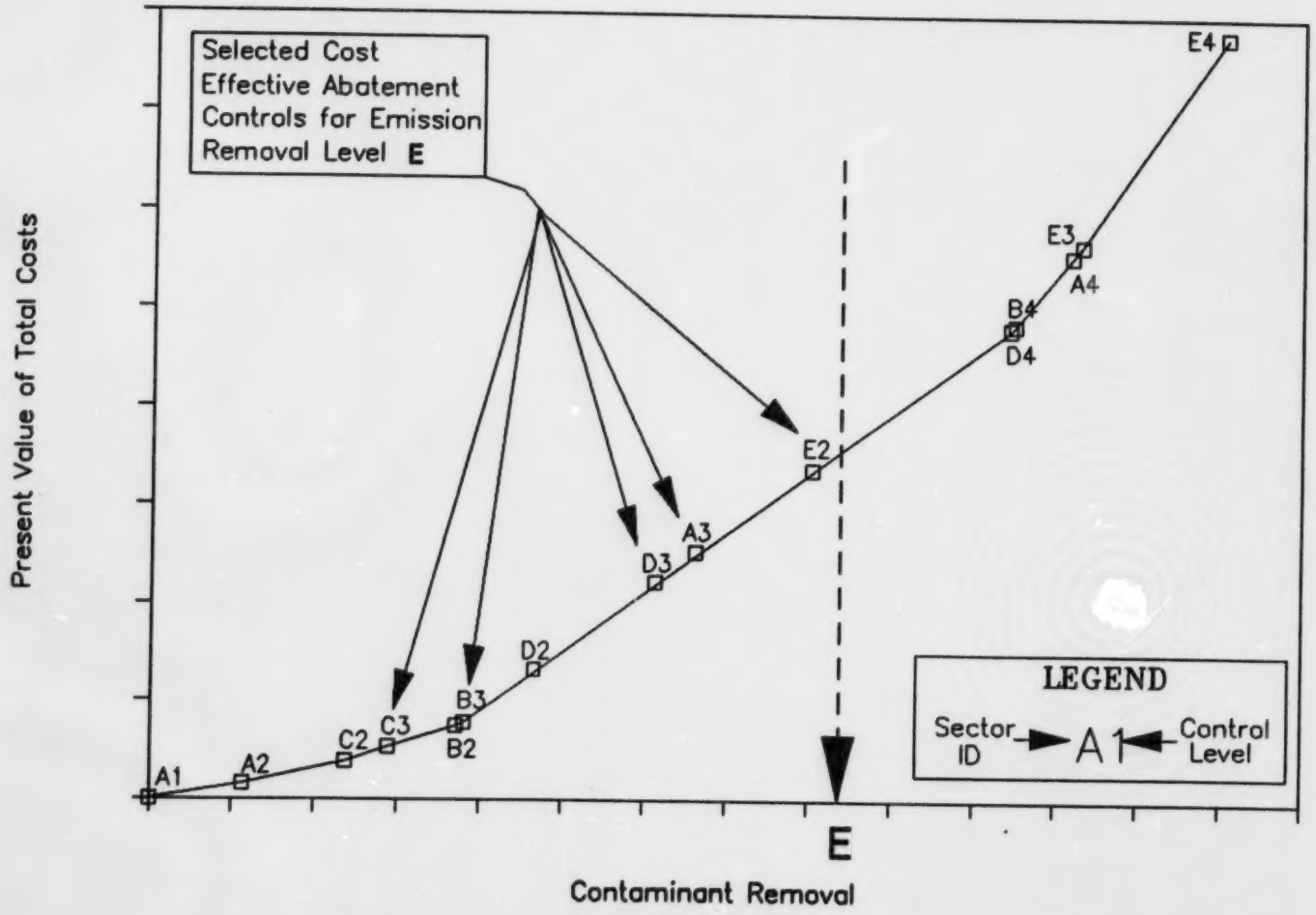

Figure 2.3 Aggregate Abatement Cost Curve

modelling assumption that operating and maintenance costs vary in direct proportion to base case emission levels. These changes in costs can cause the abatement cost function for a source or sector to become concave. Results must therefore be reviewed carefully to identify problems with concavity.

It is also possible to conduct a "what if" analysis focussing on sector-specific contingencies. This entails pre-specifying a level of control for a given source or sector. The options here include:

- excluding a specific source, sector or control option (causing data points to be omitted when defining the aggregate abatement cost function);

- forcing certain control options into the strategy (corresponding SO_2 or NO_x removals are subtracted from the provincial removal target and the selection of remaining control options is based on this net figure);

- assuming that 1994 Regulatory emission reductions are not achieved by the big four sources (the shortfall is manually added to the target and must be made up by removals from other sectors).

2.6 Sample Calculations

A two sector example is used for purposes of illustration here.

Base Case emissions for sector A and sector B are 2,099 Tonnes/yr and 14,821 Tonnes/yr, respectively and the data points for their abatement cost functions are:

Sector A

Control Option	NO_x Emission (Tonnes/yr)	Emission Reduction	Capital Cost (million $)	Operating Cost (million $)
BCE	2,099	0%	0	0
SNCR	860	59%	$13.90	$ 3.10
SCR	335	84%	$65.20	$11.46

Sector B

Control Option	Emission (Tonnes/yr)	Percent Reduction	Capital Cost (million $)	Operation Cost (million $)
BCE	14,821	0	0	0
SC	13,627	8	$ 8.30	$ 1.30
SNCR	6,369	57	$ 76.50	$16.80
SCR	2,814	81	$273.40	$48.08

where: BCE = Base Case Emission for the Sector;
SC = Stage Combustion-Boiler;
SNCR = Selective Non-Catalytic Reduction-All Streams;
SCR = Selective Catalytic Reduction-All Streams.

The incremental or discrete contaminant removal for control option "A" are calculated as:

$$DCR_i = (RED_i \times BCE) - DCR_{i-1}$$

where: DCR_i = Discrete Contaminant Removal for i^{th} technology;
RED_i = Percent Reduction for i^{th} technology.

The marginal costs are calculated by employing the following equation:

$$MC_i = (PV_i - PV_{i-1})/(DCR_i \times PF)$$

where MC_i = Marginal Cost for i^{th} technology;
PV_i = Present Value of cost for i^{th} technology;
PV_{i-1} = Present Value of costs for $i-1^{th}$ technology;
DCR_i = Discrete Contaminant Removal for i^{th} technology;
PF = Present Value factor.

(The denominator in this equation is the present value of emission removals as described on page 7 above.)

The results for industrial sectors A and B are given as follows:

Industrial Sector A

Control Option (code)		Present Value (million $)	Discrete Removal (Tonnes/yr)	Marginal Cost ($/Tonne)
BCE	(A1)	0	0	0
SNCR	(A2)	$ 42.00	1238	$ 3,170
SCR	(A3)	$172.27	525	$26,400

Industrial Sector B

Technologies		Present Value (million $)	Discrete Removal (Tonnes/yr)	Marginal Cost ($/Tonne)
BCE	(B1)	0	0	0
SC	(B2)	$ 20.44	1185	$ 1,850
SNCR	(B3)	$233.42	7258	$ 3,140
SCR	(B4)	$722.48	3555	$14,700

A nominal interest rate of 13%, an inflation rate of 6% and a time horizon of 15 years were used in the above calculations.

The next step involves ranking the marginal costs from both sectors in ascending order and summing the discrete removals:

Sorted Control Options	Increasing Marginal Cost ($/Tonnes)	Discrete Removal (Tonnes/yr)	Cumulative Removals (Tonnes/yr)
A1	0	0	0
B1	0	0	0
B2	$ 1,850	1,185	1,185
B3	$ 3,140	7,258	8,443
A2	$ 3,170	1,238	9,681
B4	$14,700	3,555	13,236
A3	$26,400	525	13,761

The target removal (TR = 9500 Tonnes/yr) level is compared with the cumulative removal using a "compare and check" procedure which is summarized in a flow chart in Figure 2.4. The results are given as follows:

Control Options	Cumulative Removals (S_i) (Tonnes/yr)	Is Summation less than TR?	Is abs(S_i-TR) >abs(S_{i+1}-TR)?	Model Selection
A1	0	YES	NA	IN
B1	0	YES	NA	IN
B2	1,185	YES	NA	IN
B3	8,443	YES	YES	IN
A2	9,681	NO	NO	IN
B4	13,236	STOP	—	—
A3	13,761	—	—	—

where: abs(S_i-TR) = absolute value of summation i - target removal;
abs(S_{i+1}-TR) = absolute value of summation i-1 - target removal;
NA = Not Applicable.

Since only the technology with the highest removal efficiency in each industrial sector is reported for that sector (see Section 2.4), the final choice is:

Control Options	Emission Reduction	Model Selection	Is % reduction highest in the sector	Final Choice
A1	0	IN	NO	—
B1	0	IN	NO	—
B2	8%	IN	NO	—
B3	57%	IN	YES	IN
A2	59%	IN	YES	IN
B4	81%	—	—	—
A3	84%	—	—	—

The abatement strategy includes technology B3 [SCR] for sector B and technology A2 [SCR] for sector A based on the target removal of 9500 Tonnes/year. The aggregate emission removal level is equal to 9681 tonnes per year (0 + 0 + 1185 + 7258 + 1238 = 9681).

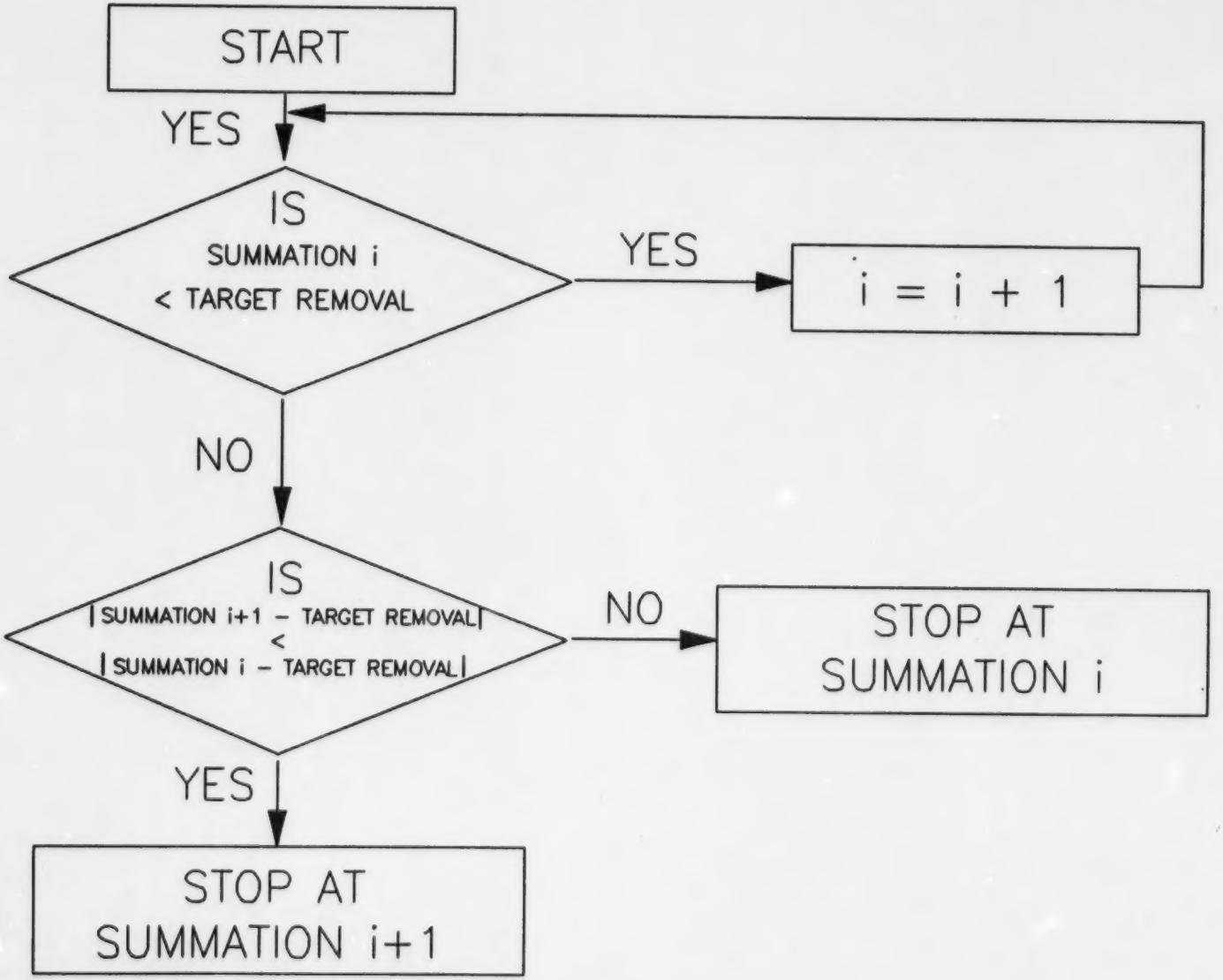

Figure 2.4 Flow Chart for "COMPARE AND CHECK" Procedure

3.0 PREPARATION OF DATA INPUTS

3.1 Base Case Emissions

There are ten major industrial sectors and four individual corporations that are identified as significant sources of SO_2 and NO_x emissions (Table 3.1). Primary data describing base case emission levels, as well as the costs and removal efficiencies of alternative control technologies were generated by Senes Consultants Limited in Phase II of this study. (See "Phase II - Countdown Acid Rain Future Abatement Strategies", Senes, 1989(b).)

Detailed data tables for industrial sectors and major sources are provided in the Phase I and II reports by Senes. Data extracted from this report for Phase III work included emission levels, control technologies, removal efficiencies and their capital and operating costs. Base case emissions are indicated in Table 3.2.

Table 3.1 Sector and Sources Considered for Abatement Strategies

CODE	SECTOR or SOURCE	INCLUDED IN SO_2 SCENARIOS	INCLUDED IN NO_x SCENARIOS
A	Primary Metals	Yes	No
B	Food and Beverages	Yes	Yes
C	Rubber and Plastics	No	Yes
D	Leather, Textile and Clothing	Yes	Yes
E	Paper and Allied Products	Yes	Yes
F	Metal Fabrication Machinery Industries	Yes	Yes
G	Transportation Equipment Industries	Yes	Yes
H	Non-Metallic Mineral Products	Yes	Yes
I	Chemical and Petroleum Products	Yes	Yes
J	Other Groups	Yes	Yes
K	INCO	Yes	No
L	Ontario Hydro	Yes	Yes
M	Falconbridge	Yes	No
N	Algoma	Yes	No
O	Mobile Sources	No	Yes

Note: NO_x emissions for Falconbridge and Algoma were not considered to be significant for purposes of this study.

TABLE 3.2
BASE CASE EMISSIONS
STATUS QUO SCENARIO - OPTION 1

SOURCE OR SECTOR	SO_2 (tonnes/year)	NO_x (tonnes/year)
INCO	265,000	4,900
Ontario Hydro	175,000	61,333 [1]
Algoma Ore Division (Wawa)	125,000	260
Falconbridge Nickel Mines	100,000	20
Industrial Sectors:		
Food/Beverage/Tobacco	1,647	2,881
Rubber Plastics	185	386
Leather/Textile/Clothing	7,359	1,254
Paper Products & Allied Industries	30,621	12,179
Primary Metals	14,219	672
Metal Fabricating/Machinery Industries	29,038	14,662
Transportation Equipment Industries	1,801	2,099
Non-Metallic Mineral Products	20,249	9,756
Chemical & Petroleum Products	69,902	27,892
Misc. Manufacturing	192	267
Other Major Groups	5,318	4,250
Industry Sub Total	845,531	142,811
Area Sources:		
Metro Toronto area	18,603	101,812
Niagara-Hamilton-Toronto Corridor	24,154	202,954
Balance of Ontario	6,067	125,124
Marine Sources	6,530	5,434
Area Source Sub Total	55,354	435,324
TOTAL	900,885	578,135

Source: Senes, 1989(a). "Phase I Countdown Acid Rain Future Abatement Strategies" (Table 8).

Note: 1. Equivalent to 40,000 tonnes of NO_x/year as per Regulation 281/87

It should be noted that Ontario will meet SO_2 emission limits of 885,000 tonnes per year in 1994. The higher value of 900,835 tonnes per year arises from the implicit assumption that Algoma Steel Corp. (Wawa) and Falconbridge will increase emissions to their maximum acceptable levels.

3.2 Emission Control Costs

Data for the following emission control options are presented by Senes (1989(b)):

SO_2 Control technologies
- fuel oil cleaning (fuel desulfurization)
- fuel switching to natural gas
- lime spray dryer treatment of emissions
- limestone flue gas desulfurization (FGD) of emissions

NO_x Control technologies
- low excess air feed to burners
- staged combustion in burners
- selective non-catalytic reduction of emissions
- selective catalytic reduction of emissions
- catalytic converters (mobile sources only)

Treatment processes for emissions are applied to boiler emissions, process emissions or both.

Senes data for fuel oil cleaning and for fuel switching to natural gas required some further refinement prior to being used in the analysis of abatement strategies.

Desulfurization of fuel oil reduces SO_2 emissions from boilers while increasing emissions of the petroleum refining sector. Data describing desulfurization were provided by Senes in aggregate form for the

petroleum-refining industry. These data were converted into average costs per net kilogram of sulfur removed and then distributed across the individual sources and sectors using desulfurized fuel oil. In so doing, it was assumed that desulfurized fuel oil could be supplied by the petroleum industry in quantities corresponding to the demand from individual manufacturing sectors and that an all or nothing conversion to desulfurization by the refinery industry was not necessary. Two data points were created with the desulfurization data, one for fuel desulfurization alone and one for fuel desulfurization combined with limestone flue gas desulfurization. Details of the fuel desulfurization calculations are provided in Appendix B3.

In evaluating fuel switching from fuel oil to natural gas, Senes assumed that there would be no bottle necks in the capacity to supply additional natural gas. Given the short time frame to implementation by 1994, it is likely that conversion will only be feasible along existing gas pipelines. In the absence of specific information regarding access of establishments in each sector or source to natural gas supply lines, it was assumed that conversion to natural gas would be limited to 10% of the maximum conceivable level (i.e. complete conversion).

In the case of NO_x control options, the low excess air option is estimated to actually reduce boiler operating and maintenance costs. The cost savings are sufficient to suggest overall cost savings in net present value terms after accounting for capital costs; however, removal efficiencies are relatively modest with this option. In light of these low removal efficiencies and in order to be conservative in the assumptions regarding control costs, the low excess air option was not incorporated into the final abatement cost functions used in the model.

NO_x controls for mobile sources, provided by MacLaren Plansearch (1988), included two options, (1) a 3-way catalytic converter required on new cars by federal regulation, and (2) a more effecient catalytic converter that

exceeds federal standards. Assumptions and calculations made to generate control option data from the MacLaren results in the format required for this study are documented in Appendix D.

Final data for SO_2 and NO_x are provided in Tables 3.3 and 3.4. These data were plotted and analyzed as discussed in Section 2.3 in order to generate abatement cost functions. Control technologies included in the abatement cost function are noted in Tables 3.3 and 3.4.

TABLE 3.3: SO2 EMISSION CONTROL COST DATA

Source or Sector	Cost Function Code	Emissions of SO2 (T/yr)	Emission Reduction	Capital Costs ---- (M 1987 $) -----	Operating Costs -----	Control Technology Code
PRIMARY METALS	A1	14,129	0%	$0.00	$0.00	0
	A2	725	95%	$2.10	$7.20	4
FOOD & BEVERAGE	B1	1,421	0%	$0.00	$0.00	0
	out	1,401	1%	$0.40	$0.20	2
	out	1,364	4%	$0.00	$0.46	6
	B2	1,322	7%	$0.06	$0.00	1
	out	614	57%	$161.20	$50.10	5
	b3	570	60%	$11.90	$5.20	3
	b4	398	72%	$161.20	$7.52	7
TEXTILE INDUSTRIES	D1	7,359	0%	$0.00	$0.00	0
	D2	7,072	4%	$0.03	$0.00	1
	D3	5,004	32%	$0.00	$1.31	6
	out	4,894	33%	$9.20	$3.10	3
	out	4,621	37%	$90.80	$28.20	5
	out	4,489	39%	$90.80	$3.38	7
	D4	3,569	52%	$8.10	$1.88	2
PAPER & ALLIED PRODUCTS	E1	30,516	0%	$0.00	$0.00	0
	E2	29,143	5%	$0.06	$0.00	1
	out	22,673	26%	$104.40	$32.10	4
	out	18,828	38%	$16.60	$5.40	3
	out	18,371	40%	$565.50	$165.40	5
	out	17,547	43%	$6.20	$1.87	2
	out	16,601	46%	$565.50	$29.77	7
	E3	8,545	72%	$0.00	$1.61	6
METAL FABRICATION	F1	29,480	0%	$0.00	$0.00	0
	F2	29,109	1%	$0.08	$0.00	1
	out	26,326	11%	$18.00	$7.00	3
	out	26,149	11%	$215.60	$67.00	5
	out	19,663	33%	$41.60	$10.20	2
	F3	19,162	35%	$0.00	$1.50	6
	F4	13,738	53%	$215.60	$8.71	7
TRANSPORTATION EQUIPMENT	G1	1,801	0%	$0.00	$0.00	0
	G2	1,622	10%	$0.03	$0.00	1
	G3	648	64%	$0.00	$0.42	6
	out	281	84%	$268.90	$78.40	5
	G4	279	85%	$6.90	$2.44	3
	G5	50	97%	$268.90	$12.50	7
NON-METALLIC MINERAL PRODUCTS	H1	20,248	0%	$0.00	$0.00	0
	out	19,478	4%	$8.40	$3.60	3
	out	19,397	4%	$187.80	$56.60	5
	out	19,316	5%	$187.80	$7.36	7
	H2	18,223	10%	$0.00	$0.39	6
	H3	4,029	80%	$27.70	$7.70	2

(continued)

TABLE 3.3 (continued)

Source or Sector	Cost Function Code	Emissions of SO2 (T/yr)	Emission Reduction	Capital Costs ---- (M 1987 $) -----	Operating Costs -----	Control Technology Code
CHEMICAL & PETROLEUM PRODUCTS	I1	69,384	0%	$0.00	$0.00	0
	I2	66,539	4%	$0.14	$0.00	1
	out	62,446	10%	$0.00	$11.41	6
	I3	53,009	24%	$3.30	$2.00	2
	out	49,887	28%	$209.10	$65.20	5
	I4	45,238	35%	$30.40	$10.70	3
	I5	39,133	44%	$209.10	$14.34	7
	I6	35,108	49%	$246.90	$79.00	4
OTHER GROUPS	J1	4,805	0%	$0.00	$0.00	0
	J2	4,377	9%	$0.20	$0.00	1
	J3	2,595	46%	$0.00	$1.75	6
	out	1,552	68%	$750.40	$226.20	5
	J4	1,158	76%	$40.90	$17.20	3
	J5	577	88%	$750.40	$38.40	7
INCO	K1	265,000	0%	$0.00	$0.00	0
	K2	238,500	10%	$37.80	$13.90	4
	K3	212,000	20%	$52.40	$20.00	4
	K4	185,500	30%	$64.20	$25.20	4
	K5	132,500	50%	$83.70	$34.40	4
ONTARIO HYDRO	L1	175,000	0%	$0.00	$0.00	0
	L2	157,500	10%	$62.30	$4.70	5
	L3	140,000	20%	$124.60	$9.40	5
	L4	122,500	30%	$186.90	$14.10	5
	L5	87,500	50%	$311.50	$23.50	5
FALCONBRIDGE	M1	100,000	0%	$0.00	$0.00	0
	M2	90,000	10%	$14.30	$9.30	2
	M3	80,000	20%	$23.40	$22.20	2
	M4	70,000	30%	$30.30	$36.50	2
	M5	50,000	50%	$42.50	$71.40	2
ALGOMA	N1	125,000	0%	$0.00	$0.00	0
	out	112,500	10%	$13.40	$0.10	2
	N2	100,000	20%	$22.50	$0.10	2
	out	87,500	30%	$21.90	$35.60	2
	N3	62,500	50%	$27.20	$48.00	2

SOURCE: Adapted from Senes, 1989(b)

NOTES: Cost Function Codes:

out - Control option is not used in the cost function.

A1,A2,... - First, second,... point in the cost function for sector "A".

Control Technology Codes:

0 Base Case
1 Fuel Switched to Natural Gas -- Boilers
2 Lime Spray Dryer -- Process Stream
3 Lime Spray Dryer -- Boilers
4 Limestone Flue Gas Desulphurization -- Process Streams
5 Limestone Flue Gas Desulphurization -- Boilers
6 Fuel Desulphurization
7 Fuel Desulphurization Plus Limestone Flue Gas Desulphurization

TABLE 3.4: NOX EMISSION CONTROL COST DATA

Source or Sector	Cost Function Code	Emissions of NOX (T/yr)	Emission Reduction	Capital Costs ----- (M 1987 $) -----	Operating Costs	Control Technology Code
FOOD & BEVERAGE	B1	2,873	0%	$0.00	$0.00	0
	B2	2,729	5%	$0.60	($1.30)	1
	B3	2,585	10%	$3.90	$0.80	2
	out	1,265	56%	$30.00	$6.60	3
	B4	595	79%	$137.10	$24.10	4
RUBBER & PLASTIC PRODUCTS	C1	386	0%	$0.00	$0.00	0
	out	343	11%	$0.10	($0.40)	1
	C2	300	22%	$0.70	$0.10	2
	C3	154	60%	$4.00	$0.90	3
	C4	58	85%	$18.90	$3.33	4
TEXTILE INDUSTRY	D1	1,180	0%	$0.00	$0.00	0
	out	1,058	10%	$0.10	($0.40)	1
	D2	937	21%	$1.80	$0.10	2
	D3	508	57%	$3.70	$0.80	3
	D4	228	81%	$17.20	$3.00	4
PAPER & ALLIED PRODUCTS	E1	11,429	0%	$0.00	$0.00	0
	out	10,225	11%	$1.50	($2.80)	1
	E2	9,021	21%	$5.00	$2.00	2
	E3	4,682	59%	$88.40	$19.40	3
	E4	1,871	84%	$413.50	$72.70	4
METAL FABRICATION	F1	14,812	0%	$0.00	$0.00	0
	out	14,207	4%	$1.90	($4.30)	1
	F2	13,602	8%	$8.30	$1.30	2
	F3	6,328	57%	$76.50	$16.80	3
	F4	2,792	81%	$273.40	$48.10	4
TRANSPORTATION EQUIPMENT	G1	2,099	0%	$0.00	$0.00	0
	out	1,972	6%	$0.30	($2.40)	1
	out	1,844	12%	$9.00	$0.70	2
	G2	860	59%	$13.90	$3.10	3
	G3	343	84%	$65.20	$11.50	4
NON-METALLIC MINERAL PRODUCTS	H1	9,826	0%	$0.00	$0.00	0
	out	9,406	4%	$0.80	($8.90)	1
	out	8,986	9%	$3.10	$2.50	2
	H2	4,523	54%	$46.90	$10.60	3
	H3	2,313	76%	$316.50	$56.70	4

(continued)

TABLE 3.4 (continued)

Source or Sector	Cost Function Code	Emissions of NOX (T/yr)	Emission Reduction	Capital Costs ---- (M 1987 $) ----	Operating Costs	Control Technology Code
CHEMICAL & PETROLEUM	I1	28,587	0%	$0.00	$0.00	0
PRODUCTS	out	27,149	5%	$1.70	($17.60)	1
	out	25,708	10%	$8.60	$5.00	2
	I2	12,958	55%	$95.30	$20.90	3
	I3	6,446	77%	$437.70	$77.00	4
OTHER GROUPS	J1	4,298	0%	$0.00	$0.00	0
	out	3,814	11%	$3.10	($5.40)	1
	J2	3,330	23%	$9.10	$1.60	2
	J3	2,285	47%	$65.80	$14.40	3
	J4	1,447	66%	$196.60	$35.60	4
ONTARIO HYDRO	L1	61,333	0%	$0.00	$0.00	0
	L2	55,200	10%	$13.00	$2.50	4
	L3	49,066	20%	$26.10	$5.00	4
	L4	42,933	30%	$39.10	$7.50	4
	L5	30,667	50%	$65.10	$12.50	4
	L6	24,884	59%	$77.10	$14.90	4
MOBILE SOURCES	01	244,952	0%	$0.00	$0.00	0
	02	95,531	61%	$974.37	$0.00	5
	03	73,486	70%	$1,282.91	$0.00	5

SOURCE: Adapted from Senes, 1989(b) and MacLaren Plansearch, (1988).

NOTES: Cost Function Codes:

out - Control option is not used in the cost function.

A1,A2,... - First, second,... point in the cost function for sector "

Control Technology Codes:

0 Base Case
1 Low Excess Air
2 Staged Combustion
3 Selective Non-Catalytic Combustion
4 Selective Catalytic Reduction
5 Catalytic Converter

4.0 ANALYSIS OF ABATEMENT STRATEGIES

4.1 Overview

This chapter discusses the modelling results for the "Phase III - Countdown Acid Rain Future Abatement Strategies" exercise.
The first set of results, generated by the SO_2 abatement strategy model, comprise seven principal SO_2 emission reduction scenarios. The second set of results, generated by the NO_x abatement strategy model, comprises five principal NO_x emission reduction scenarios.

These SO_2 and the NO_x emission reduction scenarios show:

1) The impact of different removal targets on the abatement strategies;
2) The impact when large sources (such as INCO and Hydro) fail to fulfill their 1994 regulated targets for abatement;

Additional analyses investigated the impact of forming a more equitable distribution of emission reductions across sectors and of alternative assumptions regarding variables like the interest rate.

4.2 SO_2 Abatement Strategies

The primary analysis of SO_2 abatement scenarios concerned the implications of reducing total emissions from the base case 1994 level of 900,885 t/yr (from Table 3.2). A range of conditions were examined including different levels of reduction as well as higher initial starting emission levels resulting from a failure to meet 1994 targets; these are outlined in Table 4.1. Additional scenarios examine the implications of changing financial variables and of forcing all emitters to cut back by the same percentage (an equity scenario). These analyses are briefly summarized below.

The first three scenarios reveal how sensitive overall emission control costs are to the required level of reduction (Table 4.2). The 30% reduction, representing a reference case, entails a total cost, measured in present value terms, of $887 M. A third of this is for start-up investments. Dropping the target reduction by 20 points to 10% (Scenario 2), reduces total costs by 82% to $159 M, while a comparable increase to a 50% targeted reduction increases overall costs six-fold to $5,338 M.

Table 4.1 Primary SO_2 Abatement Strategy Scenarios

SO_2 Scenario Number	Starting Emission Level (t/yr)	Reduction From[1] 1994 Base Case Level	Target Reduction (t/yr)	Remaining Emissions (t/yr)
1	900,885	30%	270,266	630,619
2	900,885	10%	90,089	810,796
3	900,885	50%	450,443	450,442
12[2]	1,330,885	0%	430,000	900,885
13[2]	1,115,885	0%	215,000	900,885
14[3]	1,062,518	0%	161,633	900,885
15[3]	981,702	0%	80,817	900,885

NOTES:

1 The 1994 base case emission is 900,885 tonnes/yr.

2 INCO fails to meet its 1994 target and remains at its 1985 emission level (Scenario 12) or achieves 1/2 of its 1994 reduction (Scenario 13). It does not contribute to reduction beyond 1994.

3 Hydro fails to meet its 1994 target and remains at its 1985 emission level (Scenario 14) or achieves 1/2 of its 1994 reduction (Scenario 15).

TABLE 4.2: SO2 ABATEMENT STRATEGIES FOR 30%, 10% AND 50% EMISSION REDUCTIONS

Control Option	Percent Reduct'n	Capital Cost	Operat'g Cost	Present Value	Marginal Cost	SO2 Removal
		---------- (M 1987 $) ----------			(1987 $/T)	(T/yr)
SCENARIO 1 - 30% REDUCTION						
(Target reduction = 270,266 tonnes/yr)						
A - FGD(process)	94.9%	$2.10	$7.20	$69.35	$550	13,494
B - Lime Spray Dry(process)	6.9%	$0.06	$0.00	$0.06	$65	99
D - Fuel Clean'g	32.0%	$0.00	$1.31	$12.24	$632	2,355
E - FGD(process)	72.0%	$0.00	$1.61	$15.04	$78	21,972
F - Lime Spray Dry(boilers)	35.0%	$0.00	$1.50	$14.01	$150	10,318
G - Fuel Clean'g	64.0%	$0.00	$0.42	$3.93	$429	1,153
H - Lime Spray Dry(boilers)	10.0%	$0.00	$0.39	$3.64	$193	2,025
I - Fuel Clean'g	23.6%	$3.30	$2.00	$21.98	$173	16,375
J - N.Gas	8.9%	$0.20	$0.00	$0.20	$50	427
K - FGD(process)	50.0%	$83.70	$34.40	$405.01	$327	132,500
L - FGD(boilers)	30.0%	$186.90	$14.00	$317.66	$650	52,500
N - Lime Spray Dry(process)	20.0%	$22.50	$0.10	$23.43	$100	25,000
TOTAL		$298.76	$62.93	$886.55		278,217
SCENARIO 2 - 10% REDUCTION						
(Target reduction = 90,089 tonnes/yr)						
B - Lime Spray Dry(process)	6.9%	$0.06	$0.00	$0.06	$65	99
D - N.Gas	3.9%	$0.03	$0.00	$0.03	$11	287
E - FGD(process)	72.0%	$0.00	$1.61	$15.04	$78	21,972
F - Lime Spray Dry(boilers)	35.0%	$0.00	$1.50	$14.01	$150	10,318
G - N.Gas	9.9%	$0.03	$0.00	$0.03	$18	179
H - Lime Spray Dry(boilers)	10.0%	$0.00	$0.39	$3.64	$193	2,025
I - Fuel Clean'g	23.6%	$3.30	$2.00	$21.98	$173	16,375
J - N.Gas	8.9%	$0.20	$0.00	$0.20	$50	427
K - FGD(process)	10.0%	$16.74	$6.88	$81.00	$327	26,500
N - Lime Spray Dry(process)	20.0%	$22.50	$0.10	$23.43	$100	25,000
TOTAL		$42.86	$12.48	$159.43		103,181

(continued)

TABLE 4.2 (continued)

Control Option	Percent Reduct'n	Capital Cost	Operat'g Cost	Present Value	Marginal Cost (1987 $/T)	SO2 Removal (T/yr)
		---------- (M 1987 $) ----------				
SCENARIO 3 - 50% REDUCTION (Target reduction = 450,443 tonnes/yr)						
A - FGD(process)	94.9%	$2.10	$7.20	$69.35	$550	13,494
B - N.Gas	72.0%	$161.20	$7.52	$231.44	$106,421	1,023
D - Lime Spray Dry(boilers)	51.5%	$8.10	$1.88	$25.66	$1,002	3,790
E - FGD(process)	72.0%	$0.00	$1.61	$15.04	$78	21,972
F - FGD(boilers)	53.4%	$215.60	$8.71	$296.95	$5,585	15,742
G - Lime Spray Dry(boilers)	97.2%	$268.90	$12.50	$385.65	$166,157	1,751
H - FGD(boilers)	80.1%	$27.70	$7.70	$99.62	$724	16,219
I - Lime Spray Dry(boilers)	49.4%	$246.90	$79.00	$984.78	$17,070	34,276
J - Lime Spray Dry(boilers)	88.0%	$750.40	$38.40	$1,109.07	$167,231	4,228
K - FGD(process)	50.0%	$83.70	$34.40	$405.01	$327	132,500
L - FGD(boilers)	50.0%	$311.50	$23.40	$530.06	$650	87,500
M - Lime Spray Dry(process)	50.0%	$42.50	$71.40	$709.40	$1,810	50,000
N - Lime Spray Dry(process)	50.0%	$27.20	$48.00	$475.54	$1,291	62,500
TOTAL		$2,145.80	$341.72	$5,337.57		444,994

NOTE: Total base case provincial SO2 emissions assumed for this analysis are 900,885 tonnes/year. Total percentage reduction is calculated with this as a reference value.

Additional assumptions include:
15 yr equip. life 6% inflation; and 13% interest rate.

Sector designations are as follows:

A Primary Metals
B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
K INCO
L Ontario Hydro
M Faconbridge
N Algoma

These results indicate a strong non-linear response with higher reduction targets forcing reliance on removal technologies having higher costs per tonne of SO_2 removed. This is shown by the marginal costs data in Table 4.2 which increase by four orders of magnitude for some sectors as removal levels increase. The only exceptions to this are the marginal costs for INCO and Hydro - these are constant as removal efficiencies increase (see Table 4.2). Their cost functions display constant average and marginal costs over the range of removal efficiencies considered here.

Without INCO emission control options the maximum attainable reduction in emissions is 312,500 tonnes/yr at a present value cost of $4,933 M. If INCO remains at 1985 emission levels (Scenario 12) this limit is reached and the 1994 reduction targets can not be achieved (Table 4.3). In fact, if Scenario 12 becomes reality, the $4,933 M expenditure will leave the province at an emission level of 1.01 M tonnes/yr. This exceeds the 1994 base case emission level by 13%. Partial (50%) success in controlling INCO emissions (Scenario 13, Table 4.3) can considerably alleviate the cost burden incurred by other sectors, and makes it possible to achieve the 1994 SO_2 target.

A failure by Hydro to meet its 1994 targets (Scenarios 14 and 15) has implications which are less severe though still costly. If Hydro fails to act at all, remaining therefore at 1985 emission levels, the 1994 targets can be achieved by other sectors at a cost of $321 m (Table 4.4). If Hydro achieves half of its 1994 regulated reductions, other sectors incur a cost of $78 M.

Variations in the financial assumptions had no effect on the choice of control options for the four major emitters unless a very high capital cost scenario was chosen (25% interest rate, 5 year planning horizon). In this scenario Hydro control options, having the highest capital costs, are dropped in favour of additional controls by INCO, Algoma and some of the smaller sectors. Among the smaller sectors, variations in financial variables cause some switching among control options.

TABLE 4.3: SO2 ABATEMENT STRATEGIES TO ACHIEVE 1994 EMISSION REDUCTION TARGETS WITHOUT INCO

Control Option	Percent Reduct'n	Capital Cost	Operat'g Cost (M 1987 $)	Present Value	Marginal Cost (1987 $/T)	SO2 Removal (T/yr)
SCENARIO 12 - INCO REMAINS AT ITS 1985 EMISSION LEVEL (All other sectors are at their maximum control levels.)						
(Target reduction = 430,000 tonnes/yr)						
A - FGD(process)	94.9%	$2.10	$7.20	$69.35	$550	13,494
B - N.Gas	72.0%	$161.20	$7.52	$231.44	$106,421	1,023
D - Lime Spray Dry(boilers)	51.5%	$8.10	$1.88	$25.66	$1,002	3,790
E - FGD(process)	72.0%	$0.00	$1.61	$15.04	$78	21,972
F - FGD(boilers)	53.4%	$215.60	$8.71	$296.95	$5,585	15,742
G - Lime Spray Dry(boilers)	97.2%	$268.90	$12.50	$385.65	$166,157	1,751
H - FGD(boilers)	80.1%	$27.70	$7.70	$99.62	$724	16,219
I - Lime Spray Dry(boilers)	49.4%	$246.90	$79.00	$984.78	$17,070	34,276
J - Lime Spray Dry(boilers)	88.0%	$750.40	$38.40	$1,109.07	$167,231	4,228
L - FGD(boilers)	50.0%	$311.50	$23.40	$530.06	$650	87,500
M - Lime Spray Dry(process)	50.0%	$42.50	$71.40	$709.40	$1,810	50,000
N - Lime Spray Dry(process)	50.0%	$27.20	$48.00	$475.54	$1,291	62,500
TOTAL		$2,062.10	$307.32	$4,932.56		312,494
SCENARIO 13 - INCO ACHIEVES ONE HALF OF ITS 1994 REGULATED REDUCTION						
(Target reduction = 215,000 tonnes/yr)						
A - FGD(process)	94.9%	$2.10	$7.20	$69.35	$550	13,494
B - Lime Spray Dry(process)	6.9%	$0.06	$0.00	$0.06	$65	99
D - Lime Spray Dry(boilers)	51.5%	$8.10	$1.88	$25.66	$1,002	3,790
E - FGD(process)	72.0%	$0.00	$1.61	$15.04	$78	21,972
F - Lime Spray Dry(boilers)	35.0%	$0.00	$1.50	$14.01	$150	10,318
G - Fuel Clean'g	64.0%	$0.00	$0.42	$3.93	$429	1,153
H - FGD(boilers)	80.1%	$27.70	$7.70	$99.62	$724	16,219
I - Fuel Clean'g	23.6%	$3.30	$2.00	$21.98	$173	16,375
J - Fuel Clean'g	46.0%	$0.00	$1.75	$16.35	$970	2,210
L - FGD(boilers)	50.0%	$311.50	$23.40	$530.06	$650	87,500
M - Lime Spray Dry(process)	10.0%	$14.30	$9.30	$101.17	$1,083	10,000
N - Lime Spray Dry(process)	20.0%	$22.50	$0.10	$23.43	$100	25,000
TOTAL		$389.56	$56.86	$920.66		208,128

NOTE: Total base case provincial SO2 emissions assumed for this analysis are 900,885 tonnes/year. Target reductions are based on achieving this level in 1994 without the full participation of INCO.

Additional assumptions include:
15 yr equip. life 6% inflation; 13% interest rate.

Sector designations are as follows:

A Primary Metals
B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
K INCO
L Ontario Hydro
M Falconbridge
N Algoma

TABLE 4.4: SO2 ABATEMENT STRATEGIES TO ACHIEVE 1994 EMISSION REDUCTION TARGETS WITHOUT HYDRO

Control Option	Percent Reduct'n	Capital Cost (M 1987 $)	Operat'g Cost (M 1987 $)	Present Value (M 1987 $)	Marginal Cost (1987 $/T)	SO2 Removal (T/yr)
SCENARIO 14 - HYDRO REMAINS AT ITS 1985 EMISSION LEVEL (Target reduction = 161,633 tonnes/yr)						
B - Lime Spray Dry(process)	6.9%	$0.06	$0.00	$0.06	$65	99
D - N.Gas	3.9%	$0.03	$0.00	$0.03	$11	287
E - FGD(process)	72.0%	$0.00	$1.61	$15.04	$78	21,972
F - Lime Spray Dry(boilers)	35.0%	$0.00	$1.50	$14.01	$150	10,318
G - N.Gas	9.9%	$0.03	$0.00	$0.03	$18	179
H - Lime Spray Dry(boilers)	10.0%	$0.00	$0.39	$3.64	$193	2,025
I - Fuel Clean'g	23.6%	$3.30	$2.00	$21.98	$173	16,375
J - N.Gas	8.9%	$0.20	$0.00	$0.20	$50	427
K - FGD(process)	30.0%	$50.22	$20.64	$243.00	$327	79,500
N - Lime Spray Dry(process)	20.0%	$22.50	$0.10	$23.43	$100	25,000
TOTAL		$76.34	$26.24	$321.43		156,181
SCENARIO 15 - HYDRO ACHIEVES ONE HALF OF ITS 1994 REGULATED REDUCTION (Target reduction = 80,817 tonnes/yr)						
B - Lime Spray Dry(process)	6.9%	$0.06	$0.00	$0.06	$65	99
D - N.Gas	3.9%	$0.03	$0.00	$0.03	$11	287
E - FGD(process)	72.0%	$0.00	$1.61	$15.04	$78	21,972
F - Lime Spray Dry(boilers)	35.0%	$0.00	$1.50	$14.01	$150	10,318
G - N.Gas	9.9%	$0.03	$0.00	$0.03	$18	179
H - Lime Spray Dry(boilers)	10.0%	$0.00	$0.39	$3.64	$193	2,025
I - Fuel Clean'g	23.6%	$3.30	$2.00	$21.98	$173	16,375
J - N.Gas	8.9%	$0.20	$0.00	$0.20	$50	427
N - Lime Spray Dry(process)	20.0%	$22.50	$0.10	$23.43	$100	25,000
TOTAL		$26.12	$5.60	$78.43		76,681

NOTE: Total base case provincial SO2 emissions assumed for this analysis are 900,885 tonnes/year. Target reductions are based on achieving this level in 1994 without the full participation of Hydro.

Additional assumptions include:
15 yr equip. life 6% inflation; 13% interest rate.

Sector designations are as follows:

A Primary Metals
B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
K INCO
L Ontario Hydro
M Falconbridge
N Algoma

TABLE 4.5: SO2 EQUITY-BASED ABATEMENT STRATEGY

Control Option	Percent Reduct'n	Capital Cost	Operat'g Cost	Present Value	Marginal Cost	SO2 Removal
		---------- (M 1987 $) ----------			(1987 $/T)	(T/yr)
SCENARIO 1B - 30% REDUCTION WITH UNIFORM CONTROL LEVELS IN EACH ESCTOR						
(Target reduction = 270,266 tonnes/yr)						
A - (extrapolated)	32%	n.a.	n.a.	$23.37	$550	4,550
B - (extrapolated)	32%	n.a.	n.a.	$28.66	$8,601	455
D - Fuel Clean'g	32%	$0.00	$1.31	$12.24	$632	2,355
E - (extrapolated)	32%	n.a.	n.a.	$6.17	$78	9,765
F - Lime Spray Dry(boilers)	35%	$0.00	$1.50	$14.01	$150	10,318
G - (extrapolated)	32%	n.a.	n.a.	$1.62	$429	576
H - (extrapolated)	32%	n.a.	n.a.	$33.76	$724	6,479
I - Lime Spray Dry(process)	35%	$30.40	$10.70	$130.34	$1,493	24,146
J - (extrapolated)	32%	n.a.	n.a.	$10.26	$970	1,537
K - FGD(process)	30%	$50.22	$20.64	$243.00	$327	79,500
L - FGD(boilers)	30%	$186.90	$14.00	$317.66	$650	52,500
M - Lime Spray Dry(process)	30%	$30.30	$36.50	$371.22	$1,504	30,000
N - (extrapolated)	32%	n.a.	n.a.	$204.30	$1,291	40,000
TOTAL		n.a.	n.a.	$1,396.62		262,182

NOTE: Total base case provincial SO2 emissions assumed for this analysis are 900,885 tonnes/year. Total percentage reduction is calculated with this as a reference value.

Additional assumptions include:
15 yr equip. life 6% inflation; and 13% interest rate.

Sector designations are as follows:

A Primary Metals
B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
K INCO
L Ontario Hydro
M Falconbridge
N Algoma

The equity-based scenario (Table 4.5) reveals that uniform across the board cuts in emissions entail higher overall costs due to a failure to take full advantage of low cost control options that are available in certain sectors. In the case of the 30% targeted reduction, the total cost of $1,397 M includes a $510 M penalty over the cost-effective scenario cost of $887 M (Scenario 1, Table 4.2)

4.3 NO_x Abatement Strategies

The analysis of NO_x abatement strategies parallels the SO_2 analysis in considering alternative levels of reduction, failures to meet 1994 regulation levels, the impact of financial variables and the implications of an equity-based strategy. The base case emission level is 578,135 tonnes/yr (Table 3.2). The main scenarios are described in Table 4.6

Table 4.6 Primary NO_x Abatement Strategy Scenarios

NO_x Scenario Number	Starting Emission Level (t/yr)	Reduction From[1] 1994 Base Case Level	Target Reduction (t/yr)	Remaining Emissions (t/yr)
1	578,135	30%	173,441	404,694
2	578,135	10%	57,814	520,321
3	578,135	50%	289,068	289,067
12[2]	611,239	0%	33,104	578,135
13[2]	594,687	0%	16,552	578,135

NOTES:

1 The 1994 base case emission level is 578,135 tonnes/yr.

2 Hydro fails to meet its 1994 target and remains at its 1985 emission level (Scenario 12) or achieves 1/2 of its 1994 reduction (Scenario 13).

With all sectors engaged, the maximum potential NO_x emission reduction is 266,677 tonnes/yr (46% of the base case). This level of reduction costs $6,476 M in present value terms (Scenario 3, Table 4.7). Moreover, 64% of the emission reduction comes from control of mobile sources.

As was seen for the SO_2 abatement strategies, NO_x removal costs increase rapidly at the higher levels of emission control. The maximum reduction level (Scenario 3) costs 5.4 times more than a 30% reduction and 30 times more than a 10% reduction (Scenarios 1 and 2, Table 4.7). The lowest cost options are point source controls for Hydro and 3-way catalytic converters for mobile sources (see Scenario 1 marginal costs). The mobile source controls, required by Federal regulation on new vehicles after 1987, reduce emissions by 80% from 5.0 g NO_x/mile to 1.0 g NO_x/mile. NO_x emissions will fall progressively over time with this regulation as new cars replace old cars. The reduction levels considered here for mobile sources are expected to occur by 1994.

A partial or total failure on the part of Hydro to achieve its 1994 regulation level is readily offset by federally mandated mobile source controls which are now in effect for new vehicles (Scenario 12, Table 4.8). With the mobile source control option, emission reductions far exceed the target reduction level due to the modelling approach that precludes interpolations of the data to reflect partial implementation of options.

Variations in financial variables have minimal impact on Hydro and other sectors even with very high capital cost assumptions (see Appendix A for detailed results).

Scenario 1 requires that emission controls be implemented by only mobile sources and Hydro. Forcing all sectors into an equity-based scenario at an approximately uniform level of performance in order to meet the 30% reduction target, brings nine new sectors into the strategy and raises overall costs from $1,191 M to $2,275 M (Table 4.9).

TABLE 4.7: NOX ABATEMENT STRATEGIES FOR 30%, 10% AND 50% EMISSION REDUCTIONS

Control Option	Percent Reduct'n	Capital Cost (M 1987 $)	Operat'g Cost (M 1987 $)	Present Value (M 1987 $)	Marginal Cost (1987 $/T)	NOx Removal (T/yr)
SCENARIO 1 - 30% REDUCTION (Target reduction = 173,441 tonnes/yr)						
L - Selective Catalytic Reduc'n	59%	$77.10	$14.90	$216.27	$636	36,432
O - Catalytic Converter	61%	$974.37	$0.00	$974.37	$698	149,421
TOTAL		$1,051.47	$14.90	$1,190.64		185,853
SCENARIO 2 - 10% REDUCTION (Target reduction = 57,814 tonnes/yr)						
L - Selective Catalytic Reduc'n	59%	$77.10	$14.90	$216.27	$636	36,432
SCENARIO 3 - 50% REDUCTION (All sectors are at their maximum control levels.) (Target reduction = 289,068 tonnes/yr)						
B - Selective Catalytic Reduc'n	79%	$137.10	$24.10	$362.21	$43,838	2,238
C - Selective Catalytic Reduc'n	85%	$18.90	$3.33	$49.99	$41,860	329
D - Selective Catalytic Reduc'n	81%	$17.20	$3.02	$45.44	$12,953	972
E - Selective Catalytic Reduc'n	84%	$413.50	$72.73	$1,092.78	$30,845	9,823
F - Selective Catalytic Reduc'n	81%	$273.40	$48.08	$722.48	$14,729	11,903
G - Selective Catalytic Reduc'n	84%	$65.20	$11.46	$172.27	$26,402	1,801
H - Selective Catalytic Reduc'n	76%	$316.50	$56.66	$845.75	$34,661	7,325
I - Selective Catalytic Reduc'n	77%	$437.70	$76.97	$1,156.66	$14,745	21,580
J - Selective Catalytic Reduc'n	66%	$196.60	$35.60	$529.12	$43,109	2,809
L - Selective Catalytic Reduc'n	59%	$77.10	$14.90	$216.27	$636	36,432
O - Catalytic Converter	70%	$1,282.91	$0.00	$1,282.91	$1,498	171,466
TOTAL		$3,236.11	$346.86	$6,475.87		266,677

NOTE: Total base case provincial NOx emissions assumed for this analysis are 578,135 tonnes/year. Total percentage reduction is calculated with this as a reference value.

Additional assumptions include:
15 yr life time; 6% inflation; 13% interest rate.

Sector designations are as follows:

B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
L Ontario Hydro
O Mobile Sources

TABLE 4.8: NOX ABATEMENT STRATEGIES TO MEET 1994 REGULATED REDUCTION TARGETS WITHOUT HYDRO

Control Option	Percent Reduct'n	Capital Cost	Operat'g Cost	Present Value	Marginal Cost	NOx Removal
		---------- (M 1987 $) ----------			(1987 $/T)	(T/yr)
SCENARIO 12 - HYDRO REMAINING AT ITS 1985 EMISSION LEVEL (Target reduction = 33,104 tonnes/yr)						
O - Catalytic Converter	61%	$974.37	$0.00	$974.37	$698	149,421

NOTE: Total base case provincial NOx emissions assumed for this analysis are 578,135 tonnes/year. Total percentage reduction is calculated with this as a reference value.

Additional assumptions include:
15 yr life time: 6% inflation; 13% interest rate.

Sector designations are as follows:

B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
L Ontario Hydro
O Mobile Sources

TABLE 4.9: NOX EQUITY-BASED ABATEMENT STRATEGY

Control Option	Percent Reduct'n	Capital Cost (M 1987 $)	Operat'g Cost (M 1987 $)	Present Value (M 1987 $)	Marginal Cost (1987 $/T)	NOx Removal (T/yr)
SCENARIO 18 - 30% REDUCTION WITH UNIFORM CONTROL LEVELS IN EACH SECTOR						
(Target reduction = 173,441 tonnes/yr)						
B - Selective Non-Cat'tic Comb'n	56.0%	$30.00	$6.60	$91.65	$6,503	1,609
C - (extrapolated)	50.0%	n.a.	n.a.	$9.47	$7,845	193
D - Selective Non-Cat'tic Comb'n	57.0%	$3.70	$0.80	$11.17	$2,127	673
E - Selective Non-Cat'tic Comb'n	59.0%	$88.40	$19.40	$269.60	$6,062	6,738
F - Selective Non-Cat'tic Comb'n	57.0%	$76.50	$16.80	$233.42	$3,142	8,388
G - Selective Non-Cat'tic Comb'n	59.0%	$13.90	$3.10	$42.86	$3,705	1,238
H - Selective Non-Cat'tic Comb'n	54.0%	$46.90	$10.60	$145.91	$2,944	5,310
I - Selective Non-Cat'tic Comb'n	55.0%	$95.30	$20.90	$290.51	$1,978	15,838
J - Selective Non-Cat'tic Comb'n	47.0%	$65.80	$14.40	$200.30	$18,292	2,026
L - Selective Catalytic Reduc'n	50.0%	$64.90	$12.54	$182.05	$635	30,667
O - (extrapolated)	50.0%	n.a.	n.a.	$798.43	$698	122,476
TOTAL		n.a.	n.a.	$2,275.37		195,155

NOTE: Total base case provincial NOx emissions assumed for this analysis are 578,135 tonnes/year. Total percentage reduction is calculated with this as a reference value.

Additional assumptions include:
15 yr life time; 6% inflation; 13% interest rate.

Sector designations are as follows:

B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
L Ontario Hydro
O Mobile Sources

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APPENDIX A

SO_2 AND NO_x ABATEMENT STRATEGIES - DETAILED RESULTS

TABLE A.1
SO2 SCENARIO 4 - 30% REDUCTION, 4% INFLATION

TARGETED SO2 REMOVAL LEVEL (T/yr) = 270,266

Control Option	Percent Reduction	Capital Cost	Operating Cost	Present Value	Marginal Cost	SO2 Reseval	SO2 Emission
		(M 1987 $)			(1987 $/t)	(T/yr)	
A - FGD(process)	94.9%	$2.10	$7.20	$61.34	$552	13,494	725
B - Line Spray Dry(process)	6.9%	$0.06	$0.00	$0.06	$74	99	1,322
D - Fuel Clean'g	32.0%	$0.00	$1.31	$10.78	$632	2,355	5,004
E - FGD(process)	72.0%	$0.00	$1.61	$13.25	$78	21,972	8,545
F - Line Spray Dry(boilers)	35.0%	$0.00	$1.50	$12.34	$150	10,318	19,162
G - Fuel Clean'g	64.0%	$0.00	$0.42	$3.46	$429	1,153	648
H - Line Spray Dry(boilers)	10.0%	$0.00	$0.39	$3.21	$193	2,025	18,223
I - Fuel Clean'g	23.6%	$3.30	$2.00	$19.76	$176	16,375	53,009
J - N.Gas	8.9%	$0.20	$0.00	$0.20	$57	427	4,377
K - FGD(process)	50.0%	$83.70	$34.40	$366.75	$336	132,500	132,500
L - FGD(boilers)	30.0%	$186.90	$14.00	$302.09	$701	52,500	122,500
N - Line Spray Dry(process)	20.0%	$22.50	$0.10	$23.32	$113	25,000	100,000
TOTAL		$298.76	$62.93	$816.56		278,217	456,015

NOTE: Total base case provincial SO2 emissions assued for this analysis are 900,885 tonnes/year. Total percentage reseval is calculated with this as a reference value.

Additional assuaptions include:
15 yr equip. life; 4% inflation; and 13% interest rate.

Sector designations are as follows:

A Primary Metals
B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipsent
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
K INCO
L Ontario Hydro
M Faconbridge
N Algoma

TABLE A.2

SO2 SCENARIO 5 - 30% REDUCTION, 8% INFLATION

TARGETED SO2 REMOVAL LEVEL (T/yr) = 270,266

Control Option	Percent Reduction	Capital Cost	Operating Cost	Present Value	Marginal Cost	SO2 Removal	SO2 Emission
		(M 1987 $)			(1987 $/t)	(T/yr)	
A - FGD(process)	94.9%	$2.10	$7.20	$78.74	$548	13,494	725
B - Lime Spray Dry(process)	6.9%	$0.06	$0.00	$0.06	$57	99	1,322
D - N.Gas	3.9%	$0.03	$0.00	$0.03	$10	287	7,072
E - FGD(process)	72.0%	$0.00	$1.61	$17.14	$78	21,972	8,545
F - Lime Spray Dry(boilers)	35.0%	$0.00	$1.50	$15.97	$150	10,318	19,162
G - Fuel Clean'g	64.0%	$0.00	$0.42	$4.48	$429	1,153	648
H - Lime Spray Dry(boilers)	10.0%	$0.00	$0.39	$4.15	$193	2,025	18,223
I - Fuel Clean'g	23.6%	$3.30	$2.00	$24.59	$170	16,375	53,009
J - N.Gas	8.9%	$0.20	$0.00	$0.20	$44	427	4,377
K - FGD(process)	50.0%	$83.70	$34.00	$449.87	$319	132,500	132,500
L - FGD(boilers)	30.0%	$186.90	$14.00	$335.92	$603	52,500	122,500
M - Lime Spray Dry(process)	20.0%	$22.50	$0.10	$23.56	$89	25,000	100,000
TOTAL		$298.79	$61.62	$954.71		276,149	468,083

NOTE: Total base case provincial SO2 emissions assumed for this analysis are 900,885 tonnes/year. Total percentage removal is calculated with this as a reference value.

Additional assumptions include:

15 yr equip. life; 8% inflation; and 13% interest rate.

Sector designations are as follows:

A Primary Metals
B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
K INCO
L Ontario Hydro
M Falconbridge
N Algoma

TABLE A.3

SO2 SCENARIO 6 - 30% REDUCTION, 5 YEAR PLANNING HORIZON

TARGETED SO2 REMOVAL LEVEL (T/yr) = 270,266

Control Option	Percent Reduction	Capital Cost (M 1987 $)	Operating Cost (M 1987 $)	Present Value (M 1987 $)	Marginal Cost (1987 $/t)	SO2 Reaoval (T/yr)	SO2 Eaission (T/yr)
A - FGD(process)	94.9%	$2.10	$7.20	$31.94	$571	13,494	725
B - Lime Spray Dry(process)	6.9%	$0.06	$0.00	$0.06	$147	99	1,322
D - Fuel Clean'g	32.0%	$0.00	$1.31	$5.43	$630	2,355	5,004
E - FGD(process)	72.0%	$0.00	$1.61	$6.67	$77	21,972	8,545
F - Lime Spray Dry(boilers)	35.0%	$0.00	$1.50	$6.22	$149	10,318	19,162
G - Fuel Clean'g	64.0%	$0.00	$0.42	$1.75	$425	1,153	648
H - FGD(boilers)	80.1%	$27.70	$7.70	$59.61	$986	16,219	4,029
I - Fuel Clean'g	23.6%	$3.30	$2.00	$11.59	$204	16,375	53,009
J - Fuel Clean'g	46.0%	$0.00	$1.75	$7.25	$955	2,210	2,595
K - FGD(process)	50.0%	$83.70	$34.40	$226.26	$412	132,500	132,500
L - FGD(boilers)	20.0%	$124.60	$9.30	$163.14	$1,122	35,000	140,000
M - Lime Spray Dry(process)	20.0%	$22.50	$0.10	$22.91	$221	25,000	100,000
TOTAL		$263.96	$67.29	$542.82		276,693	467,539

NOTE: Total base case provincial SO2 eaissions assued for this analysis are 900,885 tonnes/year. Total percentage reaoval is calculated with this as a reference value.

Additional assuaptions include:

5 yr equip. life; 6% inflation; and 13% interest rate.

Sector designations are as follows:

A Priaary Hetals
B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Hetal Fabrication
G Transportation Equipaent
H Hon-Hetallic Products
I Chea. & Petroleua Products
J Other Groups
K INCO
L Ontario Hydro
M Faconbridge
N Algoaa

TABLE A.4

SO2 SCENARIO 9 - 30% REDUCTION, 50 YEAR PLANNING HORIZON

TARGETED SO2 REMOVAL LEVEL (T/yr) = 270,266

Control Option	Percent Reduction	Capital Cost	Operating Cost	Present Value	Marginal Cost	SO2 Removal	SO2 Emission
		(M 1987 $)			(1987 $/t)	(T/yr)	
B - Lime Spray Dry(process)	6.9%	$0.06	$0.00	$0.06	$42	99	1,322
D - N.Gas	3.9%	$0.03	$0.00	$0.03	$7	287	7,072
E - FGD(process)	72.0%	$0.00	$1.61	$23.38	$78	21,972	8,545
F - Lime Spray Dry(boilers)	35.0%	$0.00	$1.50	$21.79	$150	10,318	19,162
G - Fuel Clean'g	64.0%	$0.00	$0.42	$6.12	$430	1,153	648
H - Lime Spray Dry(boilers)	10.0%	$0.00	$0.39	$5.66	$193	2,925	18,223
I - Fuel Clean'g	23.6%	$3.30	$2.00	$32.35	$164	16,375	53,009
J - N.Gas	8.9%	$0.20	$0.00	$0.20	$32	427	4,377
K - FGD(process)	50.0%	$83.70	$34.40	$583.33	$303	132,500	132,500
L - FGD(boilers)	30.0%	$186.90	$14.00	$390.24	$514	52,500	122,500
N - Lime Spray Dry(process)	20.0%	$22.50	$0.10	$23.95	$66	25,000	100,000
TOTAL		$296.69	$54.42	$1,087.10		262,655	467,358

NOTE: Total base case provincial SO2 emissions assumed for this analysis are 900,885 tonnes/year. Total percentage removal is calculated with this as a reference value.

Additional assumptions include:

50 yr equip. life; 6% inflation; and 13% interest rate.

Sector designations are as follows:

A Primary Metals
B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
K INCO
L Ontario Hydro
M Falconbridge
N Algoma

TABLE A-5

SO2 SCENARIO 16 - 30% REDUCTION, 25% INTEREST RATE

TARGETED SO2 REMOVAL LEVEL (T/yr) = 270,266

Control Option	Percent Reduction	Capital Cost (M 1987 $)	Operating Cost (M 1987 $)	Present Value (M 1987 $)	Marginal Cost (1987 $/t)	SO2 Reaoval (T/yr)	SO2 Emission (T/yr)
A - FGD(process)	94.9%	$2.10	$7.20	$24.65	$583	13,494	725
B - Lime Spray Dry(process)	5.9%	$0.06	$0.00	$0.06	$194	99	1,322
D - Fuel Clean'g	32.0%	$0.00	$1.31	$4.10	$629	2,355	5,004
E - FGD(process)	72.0%	$0.00	$1.61	$5.04	$77	21,972	8,545
F - Lime Spray Dry(boilers)	35.0%	$0.00	$1.50	$4.70	$148	10,318	19,162
G - Fuel Clean'g	64.0%	$0.00	$0.42	$1.32	$423	1,153	648
H - FGD(boilers)	80.1%	$27.70	$7.70	$51.82	$1,138	16,219	4,029
I - Fuel Clean'g	23.6%	$3.30	$2.00	$9.57	$222	16,375	53,009
J - Fuel Clean'g	46.0%	$0.00	$1.75	$5.48	$946	2,210	2,595
K - FGD(process)	50.0%	$83.70	$34.40	$191.46	$461	132,500	132,500
M - Lime Spray Dry(process)	50.0%	$27.20	$48.00	$177.56	$1,317	62,500	62,500
TOTAL		$144.06	$105.89	$475.77		279,193	290,039

NOTE: Total base case provincial SO2 emissions assumed for this analysis are 900,885 tonnes/year. Total percentage removal is calculated with this as a reference value.

Additional assumptions include:

5 yr equip. life; 6% inflation; and 25% interest rate.

Sector designations are as follows:

A Primary Metals
B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
K INCO
L Ontario Hydro
M Falconbridge
N Algoma

TABLE A.6

NOx SCENARIO 4 - 30% REDUCTION, 4% INFLATION

TARGETED NOx REMOVAL LEVEL (T/yr) = 173,441

Control Option	Percent Reduction	Capital Cost (M 1987 $)	Operating Cost (M 1987 $)	Present Value (M 1987 $)	Marginal Cost (1987 $/t)	NOx Removal (T/yr)	NOx Emission (T/yr)
L - Selective Catalytic Reduc'n	59%	$77.10	$14.90	$199.70	$666	36,432	24,901
O - Catalytic Converter	61%	$974.37	$0.00	$974.37	$793	149,421	95,531
TOTAL	32.1%	$1,051.47	$14.90	$1,174.07		185,853	120,432

NOTE: Total base case provincial NOx emissions assumed for this analysis are 578,135 tonnes/year. Total percentage removal is calculated with this as a reference value.

Additional assumptions include:

15 yr equip. life; 4% inflation; and 13% interest rate.

Sector designations are as follows:

B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
L Ontario Hydro
O Mobile Sources

TABLE A.7

NOx SCENARIO 5 - 30% REDUCTION, 8% INFLATION

TARGETED NOx REMOVAL LEVEL (T/yr) = 173,441

Control Option	Percent Reduction	Capital Cost (M 1987 $)	Operating Cost (M 1987 $)	Present Value (M 1987 $)	Marginal Cost (1987 $/t)	NOx Removal (T/yr)	NOx Emission (T/yr)
L - Selective Catalytic Reduc'n	59%	$77.10	$14.90	$216.27	$636	36,432	24,901
O - Catalytic Converter	61%	$974.37	$0.00	$974.37	$698	149,421	95,531
TOTAL	32.1%	$1,051.47	$14.90	$1,190.64		185,853	120,432

NOTE: Total base case provincial NOx emissions assumed for this analysis are 578,135 tonnes/year. Total percentage removal is calculated with this as a reference value.

Additional assumptions include:

15 yr equip. life; 6% inflation; and 13% interest rate.

Sector designations are as follows:

B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
L Ontario Hydro
O Mobile Sources

TABLE A.8

NOx SCENARIO 6 - 30% REDUCTION, 5 YEAR PLANNING HORIZON

TARGETED NOx REMOVAL LEVEL (T/yr) = 173,441

Control Option	Percent Reduction	Capital Cost	Operating Cost	Present Value	Marginal Cost	NOx Removal	NOx Emission
		(M 1987 $)			(1987 $/t)	(T/yr)	
E - Staged Combustion	21%	$5.00	$2.00	$13.29	$1,336	2,398	9,021
L - Selective Catalytic Reduc'n	59%	$77.10	$14.90	$138.85	$920	36,432	24,901
O - Catalytic Converter	61%	$974.37	$0.00	$974.37	$1,574	149,421	95,531
TOTAL	32.6%	$1,056.47	$16.90	$1,126.51		188,251	129,453

NOTE: Total base case provincial NOx emissions assumed for this analysis are 578,135 tonnes/year. Total percentage removal is calculated with this as a reference value.

Additional assumptions include:

5 yr equip. life; 6% inflation; and 13% interest rate.

Sector designations are as follows:

B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
L Ontario Hydro
O Mobile Sources

TABLE A.9

NOx SCENARIO 9 - 30% REDUCTION, 50 YEAR PLANNING HORIZON

TARGETED NOx REMOVAL LEVEL (T/yr) = 173,441

Control Option	Percent Reduction	Capital Cost (M 1987 $)	Operating Cost (M 1987 $)	Present Value (M 1987 $)	Marginal Cost (1987 $/t)	NOx Removal (T/yr)	NOx Emission (T/yr)
L - Selective Catalytic Reduc'n	30%	$38.94	$7.53	$148.24	$555	18,400	42,733
O - Catalytic Converter	61%	$974.37	$0.00	$974.37	$449	149,421	95,533
TOTAL	29.0%	$1,013.31	$7.53	$1,122.61		167,821	138,469

NOTE: Total base case provincial NOx emissions assumed for this analysis are 570,135 tonnes/year. Total percentage removal is calculated with this as a reference value.

Additional assumptions include:

50 yr equip. life; 6% inflation; and 13% interest rate.

Sector designations are as follows:

B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
L Ontario Hydro
O Mobile Sources

TABLE A.10

NOx SCENARIO 16 - 30% REDUCTION, 25% INTEREST RATE

TARGETED NOx REMOVAL LEVEL (T/yr) = 173,441

Control Option	Percent Reduction	Capital Cost	Operating Cost	Present Value	Marginal Cost	NOx Removal	NOx Emission
		(M 1987 $)			(1987 $/t)	(T/yr)	
E - Staged Combustion	21%	$5.00	$2.00	$11.27	$1,498	2,398	9,021
L - Selective Catalytic Reduc'n	59%	$77.10	$14.90	$123.78	$1,085	36,432	24,901
O - Catalytic Converter	61%	$974.37	$0.00	$974.37	$2,082	149,421	95,531
TOTAL	32.6%	$1,056.47	$16.90	$1,109.41		188,251	129,453

NOTE: Total base case provincial NOx emissions assumed for this analysis are 578,135 tonnes/year. Total percentage removal is calculated with this as a reference value.

Additional assumptions include:

5 yr equip. life; 6% inflation; and 25% interest rate.

Sector designations are as follows:

B Food & Beverage
C Rubber & Plastic Products
D Textile Industries
E Paper & Allied Products
F Metal Fabrication
G Transportation Equipment
H Non-Metallic Products
I Chem. & Petroleum Products
J Other Groups
L Ontario Hydro
O Mobile Sources

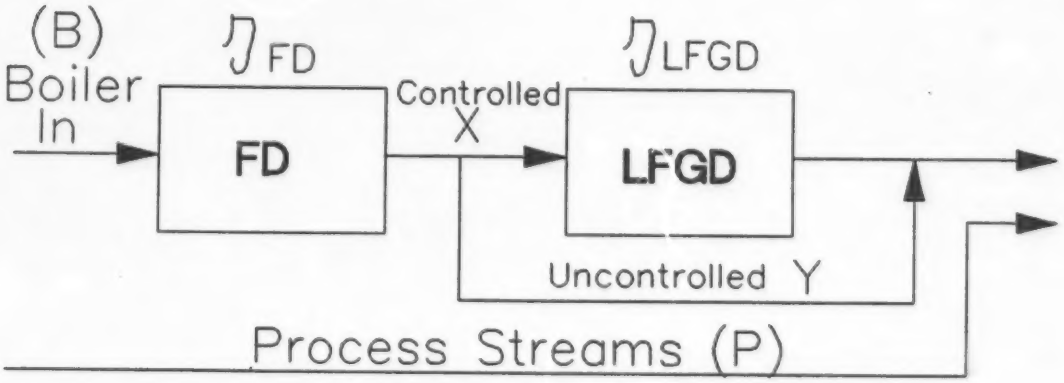
APPENDIX B

FUEL DESULFURIZATION CALCULATIONS

FIGURE B.1

LFGD+FD Removal Efficiency Calculations :

The removal efficiency for LFGD+FD control is calculated by using the following equations :



NOTES: η_{FD} — FD Removal Efficiency;
η_{LFGD} — LFGD Removal Efficiency.

$$\text{Total emission} = (1-\eta_{FD})[(1-\eta_{LFGD})X+Y] + P \quad \text{---------- (B.3.1)}$$

$$\%\ \text{Reduction}\ (\eta_{FD+LFGD}) = \left(1 - \frac{\text{Total Emission}}{B+P}\right) \times 100\% \quad \text{--------- (B.3.2)}$$

NOTE: SEE SAMPLE CALCULATIONS FOLLOWS

SAMPLE CALCULATIONS

* Using equations B.3.1 & B.3.2;

* All $_{FD}$ and $_{LFGD}$ used in the following calculations are tabulated in Table B.1 and B.2

Consider Transportation Equipment:

Total emission after FD + LFGD =
(1 - 0.84)[1 - 0.95)1600 + 197.45] + 5.4
= 49.79 Tonnes/year
% reduction = (1 - 49.70/1801) x 100 = 97.2%
FD + LFGD

Consider Metal Fabrication:

(1 - .84)[(1 - 0.95) 350 + 14134.07] + 11864.9
Total emission = 13725.1 tonnes/year
% Reduction = (1 - 13725.1/29480) x 100 = 53.4%

Consider Non-Metallic Products:

(1 - 0.87)] [(0.05) 887.4 + 53.43] + 19308.3
= Total emission = 19321 tonnes/year
% red. = (1 - 19321/20248) x 100 = 4.6%

Consider Chemical & Petroleum Products:

(1 - 0.78)[(0.05) (20533.7) + 12820.83] + 36073.3
= Total emission = 39119.75
% red. = (1 - 39119.75/69384) x 100 = 43.6%

Consider Other Groups:

(1 - 0.83)[0.05 x 3423.9 + 982.16] + 404.3
= Total E = 600.37 tonnes/year
% red. = (1 - 600.37/4805) x 100 = 87.5%

Consider Food/Beverage:

(1 - 0.85)[0.05 x 849.2 + 219.2] + 353.6
= Total E = 392.849
% r = (1 - 392.849/1421) x 100 = 72.35%

Consider Textile Industries:

(1 - 0.88)[0.05 x 2882.7 + 24.6] + 4454.5
= Total E = 4474.748
% r = (1 - 4474.748/7359) x 100 = 39.2%

Consider Paper & Allied Products

(1 - 0.82)[0105 x 12772.5 + 1561.25] + 16201.1
Total E = 16597.0775
% r = (1 - 16597.0775/30516) x 100
= 45.6%

TABLE B.1: REMOVAL EFFICIENCIES FOR FUEL DESULFURIZATION

	Total SO2 Boiler Emission (T/yr)	Total SO2 Controlled (T/yr)	SO2 Removal (T/yr)	SO2 Control Efficiency	Overall Control Efficiency
Transportation Equipment	1,795	983	825	84%	46%
Metal Fabrication	17,615	3,401	2,957	87%	10%
Non-Metallic Products	940	879	767	87%	4%
Chem. & Petroleum Products	33,311	28,638	22,362	78%	32%
Other Groups	4,400	4,132	3,440	83%	72%
Food & Beverage	1,067	1,067	905	85%	64%
Textile Industries	2,904	2,904	2,568	88%	35%
Paper & Allied Products	14,315	3,829	3,158	82%	10%

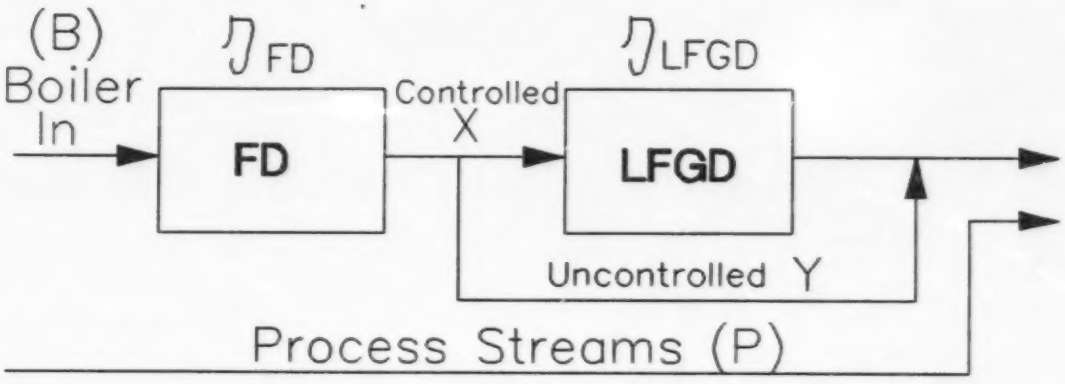
TABLE B.2: REMOVAL EFFICIENCIES FOR FLUE GAS DESULFURIZATION

	Total SO2 Boiler Emission (T/yr)	Total SO2 Controlled (T/yr)	SO2 Uncontrolled (T/yr)	SO2 Process Emission (T/yr)	SO2 Control Efficiency
Transportation Equipment	1,795	1,600	197	5	95%
Metal Fabrication	17,615	3,504	14,134	11,895	95%
Non-Metallic Products	940	887	53	19,308	95%
Chem. & Petroleum Products	33,311	20,534	12,821	36,073	95%
Other Groups	4,400	3,424	982	404	95%
Food & Beverage	1,067	849	219	354	95%
Textile Industries	2,904	2,883	25	4,455	95%
Paper & Allied Products	14,315	12,773	1,561	16,201	95%

FIGURE B.2

LFGD+FD Cost Calculations :

Assuming the capital cost is the same as the LFGD and operating cost is $\propto$ to tonnes of SO2 (controlled load).



$$\text{Operating Cost}_{(FD+LFGD)} = (1-\eta_{FD})_{LFGD} \times \text{Operating cost of} \quad \text{---- (B.3.3)}$$

$$\text{Total Cost}_{(FD+LFGD)} = \text{Operating cost}_{(FD+LFGD)} + \text{Capital cost}_{(LFGD)}$$

$$\text{---- (B.3.4)}$$

NOTES: η_{FD} —— FD Removal Efficiency;
η_{LFGD} —— LFGD Removal Efficiency.

APPENDIX C

MODEL DOCUMENTATION

COMPUTER PROGRAM DEVELOPMENT AND USE

Model Structure

The marginal cost based algorithm was implemented as a computer model, The Simple Acid Rain Model (SARM), using Lotus 1-2-3 software. It is a menu operated and macro driven program made up of three separate modules, each module comprising a separate Lotus worksheet. The three worksheets are the input worksheet, the calculation worksheet and the output worksheet. These worksheets are interconnected; thus, one worksheet can call up another worksheet by invoking a call macro. There are three temporary files generated during these calling processes. These files serve to transmit information between the three worksheets. The flow and structure of SARM are shown in Figure C.1.

General discussions on the structure of the model and the use of the model are given in the following sections. The discussion pertains to both the SO_2 model and the NO_x model which are basically the same.

Input Worksheet

The input worksheet (Table C.1) is the first interface between the user and the model. There are three main options available to the user here: the "Input/Edit" option, the "Save" option and the "Cal" option.

The "Input/Edit" option allows the user to input new data and/or edit old data. The user should input the data in the following format:

1) Column 1 (Source) -
   i) Enter - Name of emitter
   ii) Format - Label
   iii) Example - Hydro
   iv) Note - These labels are not used in subsequent displays and are entered as a guide in using this worksheet.

2) Column 2 (Technologies) -
   i) Enter - Technology index
   ii) Format - Label
   iii) Example - A1
   iv) Note - Indices should identify both the source and the technology. For instance, A1 designates the base case for source A. Integer portions of the code should be sequential (1, 2, 3, ...) and should correspond to control options with successively higher removal efficiencies.

3) Column 3 (Contaminant Emissions) -
   i) Enter - Emissions for sources in tonnes/year
   ii) Format - Numeric
   iii) Example - 12345.22
   iv) Note - Data is entered without commas and digits can be entered after the decimal but will not be displayed (i.e. 12,345).

TABLE C.1: SO2 "INPUT" WORKSHEET DATA LISTING

Source	Technology	SO2 Emissions (Tonnes/year)	% Reduction	Capital Cost (million $)	Operating Cost (million $)	Idexing 0 - Not incl'd 1 - Included	Growth Rate (%)
Dummy Source	(not app.)	0	0.0%	$0.00	$0.00	0	0
	(not app.)	0	0.0%	$0.00	$0.00	0	0
	(not app.)	0	0.0%	$0.00	$0.00	0	0
Primary Metal Products	A1	14,219	0.0%	$0.00	$0.00		0
	A2	725	94.9%	$2.10	$7.20		0
Food & Beverage Prod's	B1	1,421	0.0%	$0.00	$0.00		0
	B2	1,322	6.9%	$0.06	$0.00		0
	B3	570	59.9%	$11.90	$5.20		0
	B4	398	72.0%	$161.20	$7.52		0
Leather/Textile Prod's	D1	7,359	0.0%	$0.00	$0.00		0
	D2	7,072	3.9%	$0.03	$0.00		0
	D3	5,004	32.0%	$0.00	$1.31		0
	D4	3,569	51.5%	$8.10	$1.88		0
Paper & Allied Prod's	E1	30,516	0.0%	$0.00	$0.00		0
	E2	29,143	4.5%	$0.06	$0.00		0
	E3	8,545	72.0%	$0.00	$1.61		0
Metal Fabrication	F1	29,480	0.0%	$0.00	$0.00		0
	F2	29,109	1.3%	$0.08	$0.00		0
	F3	19,162	35.0%	$0.00	$1.50		0
	F4	13,738	53.4%	$215.60	$8.71		0
Transportation Equip't	G1	1,801	0.0%	$0.00	$0.00		0
	G2	1,622	9.9%	$0.03	$0.00		0
	G3	648	64.0%	$0.00	$0.42		0
	G4	279	84.5%	$6.90	$2.44		0
	G5	50	97.2%	$268.90	$12.50		0
Non-metallic Products	H1	20,248	0.0%	$0.00	$0.00		0
	H2	18,223	10.0%	$0.00	$0.39		0
	H3	4,029	80.1%	$27.70	$7.70		0
Chem. & Petro. Prod's	I1	69,384	0.0%	$0.00	$0.00		0
	I2	66,539	4.1%	$0.14	$0.00		0
	I3	53,009	23.6%	$3.30	$2.00		0
	I4	45,238	34.8%	$30.40	$10.70		0
	I5	39,133	43.6%	$209.10	$14.34		0
	I6	35,108	49.4%	$246.90	$79.00		0
Other Groups	J1	4,805	0.0%	$0.00	$0.00		0
	J2	4,377	8.9%	$0.20	$0.00		0
	J3	2,595	46.0%	$0.00	$1.75		0
	J4	1,158	75.9%	$40.90	$17.20		0
	J5	577	88.0%	$750.40	$38.40		0
INCO	K1	265,000	0.0%	$0.00	$0.00		0
	K2	238,500	10.0%	$16.74	$6.88		0
	K3	212,000	20.0%	$33.48	$13.76		0
	K4	185,500	30.0%	$50.22	$20.64		0
	K5	132,500	50.0%	$83.70	$34.40		0

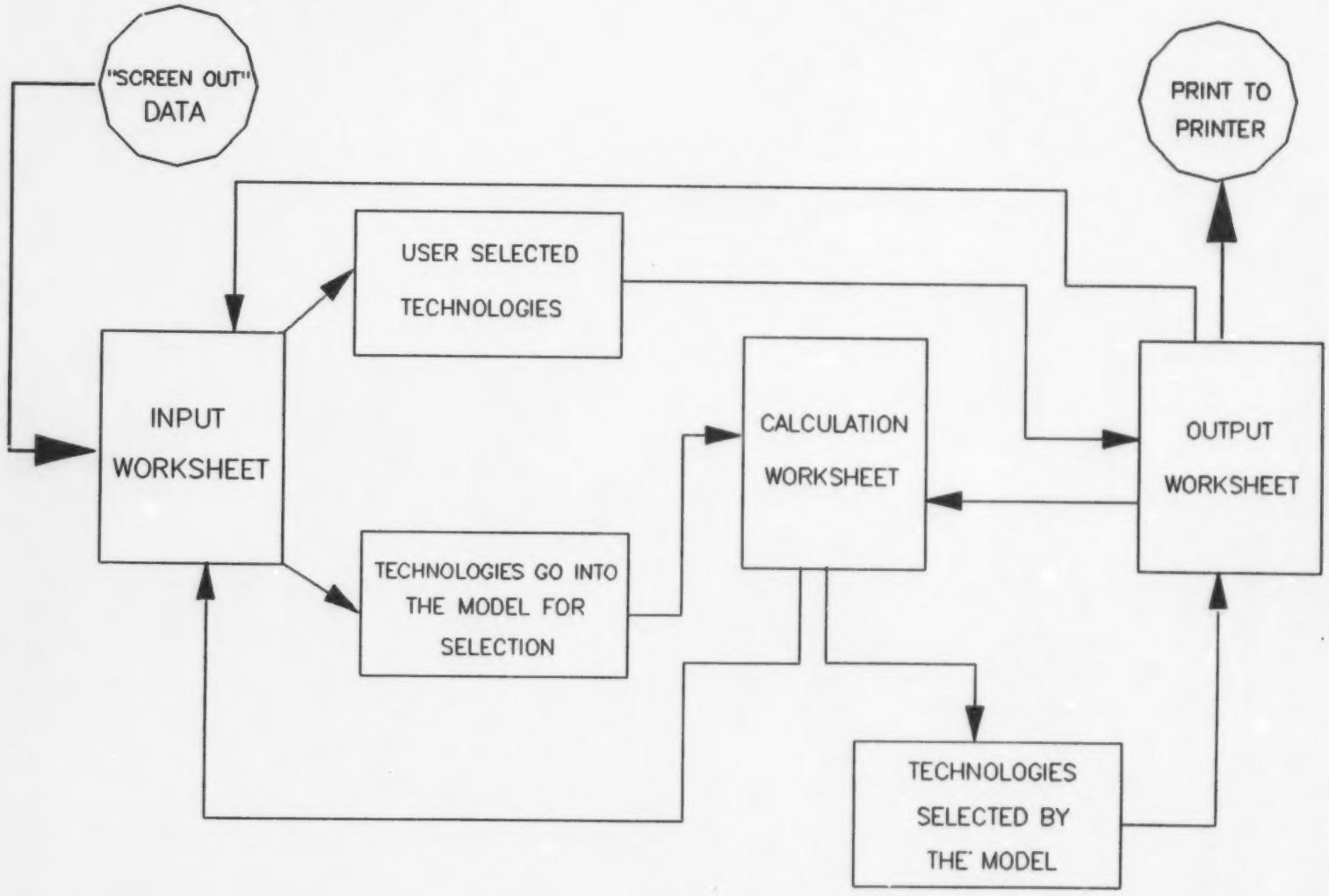


Figure c. 1 Block Diagram for SARM Flow

4) Column 4 (% Reduction) -
   i) Enter - Contaminant removal efficiency
   ii) Format - Numeric (0.0 to 1.0)
   iii) Example - 0.1
   iv) Note - For base case, users should enter 0.0. Data are displayed in percentage format (i.e. 0.10 appears as 10%).

5) Column 5 (Capital Cost) -
   i) Enter - Capital cost in millions of 1987 dollars
   ii) Format - Numeric
   iii) Example - 13.90
   iv) Note - Data are displayed in currency format (i.e. $13.90).

6) Column 6 (Operating Cost) -
   i) Enter - Operating cost in millions of 1987 dollars
   ii) Format - Numeric
   iii) Example - 3.10
   iv) Note - Currency are displayed in currency format (i.e. $3.10).

7) Column 7 (Indexing) -
   i) Enter - 0 for excluded, 1 for included and blank if model is to make the selection
   .ii) Format - Numeric
   iii) Example -

Technology	Indexing
A1	0
A2	1
A3	0
B1	
B2	
B3	
C1	0
C2	0
C3	0
D1	
D2	
D3	

   iv) Note - users can force one or more of the technologies into an abatement strategy by entering 1's in column 7, or can exclude any of the technologies from the solution by entering 0's in this column. For the column entries left blank, the model evaluates corresponding technologies based on the marginal cost ranking process.

   In the example, technology A2 is forced into the solution and technologies C1, C2 and C3 are excluded from the selection. The rest of the technologies (i.e. B1, B2, B3, D1, D2 and D3) are passed into the "calculation" worksheet and the

model will make a selection from among these based on the marginal ranking procedure and the target removal. Note that the target removal used when certain control technologies are forced into the abatement strategy is equal to the target removal input by the user minus the contaminant removed by the pre-selected technologies (this calculation is done by the model automatically). Only one technology per sector can be forced into the solution. In other words, after one of the technologies is forced into the solution; the rest of the technologies within the sector must be excluded from the solution by assigning zero's to these in Column 7.

8) Column 8 (Growth Rate) -
   i) Enter - Growth rate in percent
   ii) Format - Numeric
   iii) Example - 10
   iv) Note - Growth rate factors are used to change the emission level and corresponding operating costs for a sector. For the example above, emission levels and costs would be multiplied by the value (1 + 10/100). A negative entry would correspond to an assumed reduction in sector emissions by 1994. Note that this growth rate causes a one time change in level rather than an annual change continuing over the planning horizon.

   Individual growth rates must be assigned to each control technology. Within a sector these should be the same though they can vary across sectors.

   It is assumed that any increase in emissions stipulated using the growth rate factor is within the capacity limits of the control technology. For this reason, capital costs are not adjusted.

The next major option available to the user is "Save". It contains three sub-options; they are "Create", "Save" and "Quit". The "Create" sub-option creates two temporary files. The first file contains the user's selected technologies and it is passed to the output worksheet. The second file contains the technologies which are passed to the calculation worksheet for selection based on the marginal cost ranking procedure and the target removal. After making changes with "Input/edit", "Create" must be executed before passing control over to the "Cal" worksheet. The "Save" sub-option allows the users to save the input worksheet. The "Quit" sub-option allows the user to go back to the main menu.

The last major option available to the users is "Run". It allows the users to save the input worksheet and calls up the calculation worksheet for model execution.

There are three dummy technologies in the input file; these entries are used by the model to differentiate the user selected technologies from the model selected technologies. The users should keep these dummy entries as they appeared in the example file (they do not interfere with the results).

Calculation Worksheet

There are five major options available to the users in this module. They are the "Input" option, the "Edit" option, the "Run" option, the "Print" option and the "Quit" option.

The "Input" option allows the user to input "model parameters", such as the inflation rate, the nominal interest rate, the target removal level and the planning horizon.

The "Edit" option allows the user to save the calculation worksheet and call up the input worksheet to edit the input data.

The "Run" option performs the selection based on the marginal cost ranking procedure.

The "Print" option saves the results from a model "Run" in a temporary file which is passed to the output module. Furthermore, this option also saves the calculation worksheet and calls up the output worksheet.

The "Quit" option allows the users to quit macros and go back to the Lotus control menu. In other words, this option allows the users to edit the macros which were developed by the author.

Output Worksheet

The "Output" worksheet automatically generates the final table reporting control options for a scenario (see Table C.2). Once this table is prepared, there are four major options available to the user. They are the "Browse" option, the "Print" option, the "Edit" option and the "Calculation" option.

The "Browse" option allows the users to examine the results on screen before printing.

The "Print" option permits the users to print the results directly to the printer. Just prior to print, the user is prompted to enter a table title. For instance, the user can enter a scenario ID number for a run.

TABLE C.2: SO2 "OUTPUT" WORKSHEET DATA LISTING

TARGETED SO2 REMOVAL LEVEL (T/yr) 270,266

Control Options Chosen by Model	Emission Reduct'n	Capital Costs (M $)	Operating Cost (M $)	Present Value (M $)	Total SO2 Removal(T/yr)	SO2 Emissions(T/yr)	Comment
A1	0%	$0.00	$0.00	$0.00	0	14,219	OUT
A2	95%	$2.10	$7.20	$69.35	13494	725	IN
B1	0%	$0.00	$0.00	$0.00	0	1,421	OUT
B2	7%	$0.06	$0.00	$0.06	99	1,322	IN
B3	60%	$11.90	$5.20	$60.47	0	570	OUT
B4	72%	$161.20	$7.52	$231.44	0	398	OUT
D1	0%	$0.00	$0.00	$0.00	0	7,359	OUT
D2	4%	$0.03	$0.00	$0.03	0	7,072	OUT
D3	32%	$0.00	$1.31	$12.24	2355	5,004	IN
D4	52%	$8.10	$1.88	$25.66	0	3,569	OUT
E1	0%	$0.00	$0.00	$0.00	0	30,516	OUT
E2	4%	$0.06	$0.00	$0.06	0	29,143	OUT
E3	72%	$0.00	$1.61	$15.04	21972	8,545	IN
F1	0%	$0.00	$0.00	$0.00	0	29,480	OUT
F2	1%	$0.08	$0.00	$0.08	0	29,109	OUT
F3	35%	$0.00	$1.50	$14.01	10318	19,162	IN
F4	53%	$215.60	$8.71	$296.95	0	13,738	OUT
G1	0%	$0.00	$0.00	$0.00	0	1,801	OUT
G2	10%	$0.03	$0.00	$0.03	0	1,622	OUT
G3	64%	$0.00	$0.42	$3.93	1153	648	IN
G4	85%	$6.90	$2.44	$29.69	0	279	OUT
G5	97%	$268.90	$12.50	$385.65	0	50	OUT
H1	0%	$0.00	$0.00	$0.00	0	20,248	OUT
H2	10%	$0.00	$0.39	$3.64	2025	18,223	IN
H3	80%	$27.70	$7.70	$99.62	0	4,029	OUT
I1	0%	$0.00	$0.00	$0.00	0	69,384	OUT
I2	4%	$0.14	$0.00	$0.14	0	66,539	OUT
I3	24%	$3.30	$2.00	$21.98	16375	53,009	IN
I4	35%	$30.40	$10.70	$130.34	0	45,238	OUT
I5	44%	$209.10	$14.34	$343.04	0	39,133	OUT
I6	49%	$246.90	$79.00	$984.78	0	35,108	OUT
J1	0%	$0.00	$0.00	$0.00	0	4,805	OUT
J2	9%	$0.20	$0.00	$0.20	427	4,377	IN
J3	46%	$0.00	$1.75	$16.35	0	2,595	OUT
J4	76%	$40.90	$17.20	$201.55	0	1,158	OUT
J5	88%	$750.40	$38.40	$1,109.07	0	577	OUT
K1	0%	$0.00	$0.00	$0.00	0	265,000	OUT
K2	10%	$16.74	$6.88	$81.00	0	238,500	OUT
K3	20%	$33.48	$13.76	$162.00	0	212,000	OUT
K4	30%	$50.22	$20.64	$243.00	0	185,500	OUT
K5	50%	$83.70	$34.40	$405.01	132500	132,500	IN
L1	0%	$0.00	$0.00	$0.00	0	175,000	OUT
L2	10%	$62.30	$4.70	$106.20	0	157,500	OUT
L3	20%	$124.60	$9.30	$211.47	0	140,000	OUT
L4	30%	$186.90	$14.00	$317.66	52500	122,500	IN
L5	50%	$311.50	$23.40	$530.06	0	87,500	OUT

TABLE C.2 (continued)

TARGETED SO2 REMOVAL LEVEL (T/yr)			270,266				
Control Options Chosen by Model	Emission Reduct'n	Capital Costs (M $)	Operating Cost (M $)	Present Value (M $)	Total SO2 Removal(T/yr)	SO2 Emiss-ions(T/yr)	Comment
M1	0%	$0.00	$0.00	$0.00	0	100,000	OUT
M2	10%	$14.30	$9.30	$101.17	0	90,000	OUT
M3	20%	$23.40	$22.20	$230.76	0	80,000	OUT
M4	30%	$30.30	$36.50	$371.22	0	70,000	OUT
M5	50%	$42.50	$71.40	$709.40	0	50,000	OUT
N1	0%	$0.00	$0.00	$0.00	0	125,000	OUT
N2	20%	$22.50	$0.10	$23.43	25000	100,000	IN
N3	50%	$27.20	$48.00	$475.54	0	62,500	OUT
Sub-Totals :		$298.76	$62.93	$886.55	278,217	466,015	

TARGETED SO2 REMOVAL LEVEL (T/yr)			270,266				
Pre-specified Control Options	Percent Reduction	Capital Costs (M $)	Operating Cost (M $)	Present Value (M $)	Total SO2 Removal (T/yr	SO2 Emiss-ions (T/yr)	Comment
(not app.)	0%	$0.00	$0.00	$0.00	0	0	OUT
(not app.)	0%	$0.00	$0.00	$0.00	0	0	OUT
(not app.)	0%	$0.00	$0.00	$0.00	0	0	OUT
Sub-Totals :		$0.00	$0.00	$0.00	0	0	
TOTALS:		$298.76	$62.93	$886.55	278,217	466,015	

Notes:

Nominal interest rate (%)	13
Inflation rate (%) =	6
Time horizon (yr) =	15

The "Edit" option saves the output worksheet and calls up the input worksheet for editing the data.

The "Calculation" option saves the output worksheet and calls up the calculation worksheet. After the calculation worksheet is called up by the output worksheet; the user can change the model parameters and rerun the model with these new parameters.

Getting Started

This software requires that the user possess an IBM or 100% IBM compatible PC, XT or AT machine and the Lotus 1-2-3 software version 2.0 or above by Lotus Development Corporation. For further instructions regarding the installation of the Lotus 1-2-3 program, the user should refer to the 1-2-3 reference manual.

Prior to running the model, the user should back up the original disks. If you have a hard disk system, SARM can be copied onto the hard disk. Running SARM from the hard disk speeds up the program operation.

APPENDIX D

MOBILE SOURCE NO_x CONTROLS

The interpretation of control option data for mobile sources presented particular problems. Status quo emissions for 1994 from this source, amounting to 435,324 tonnes NO_x, are based on estimates of 1985 emissions (Senes, 1989(a)) and do not incorporate existing Federal regulations requiring 3-way calalytic converters on passenger vehicles which took effect in 1987 (MacLaren, 1988).

This treatment differs from the treatment of regulations facing the large point source emitters. The control option data from MacLaren (1988) describe a do nothing case assuming pre 1987 conditions (their Case C), the Federal regulation case (Case A) and a case involving even stricter controls (Case C). Control option capital cost and emission reduction data are presented as a time series extending from 1984 to 2002 showing progressive reductions in NO_x emissions as new vehicles equipped with catalytic converters replace old vehicles. Thus the format of control option data for mobile sources did not conform to that of other sources which had initial start-up capital costs and recurring operating costs.

Finally there were discrepancies in emissions data that could not be reconciled. The status quo NO_x emissions for licensed vehicles is given by Senes (1989(a), Table 6) as 326,603 tonnes but the corresponding value from MacLaren (1988, Table 1) is either 250,066 tonnes for 1985 or 212,701 tonnes for 1994. MacLaren's (1988) emission estimates for passenger vehicles in 1994 appear not to be reconciled, being given as 95,468 tonnes in Table 1 and 177,805 tonnes in Table 2.

Given the above noted difficulties, control option data were derived for mobile sources by making the following assumptions:

- emission control efficiencies were based on percentage reductions implied by data for 1994 from MacLaren (1988, Table 2):

  Case A = 61%, Case B = 70%

- these emission reduction efficiencies were applied to the percentage of Senes' base case emissions for licenced vehicles representing passenger vehicles in 1985 (percentage figures based on MacLaren 1988, Table 1):

  326,603 tonnes x 75% = 244,952

- cost data were based on the following information from MacLaren (1988):

  1987 cost/vehicle: Case A = $313 (updated from 1985 $)
  Case B = $413

  Emissions: Case C = 5.0 g NO_x/mile
  Case A = 1.0 g NO_x/mile
  Case B = 0.4 g NO_x/mile

Assuming a vehicle use rate of 12,000 miles/year, total capital cost data per tonne of NO_x removed annually are:

Case A $313/(12,000 mi x 4.0 g/mi x 10^{-6} g/T) = $6,521/T

Case B $413/(12,000 mi x 4.6 g/mi x 10^{-6} g/T) = $7,482/T

Final emission control data for mobile sources are:

	Emissions (tonnes)	Reduction Level	Emission Reduction (tonnes)	Capital Cost (M $ 1987)
Base Case	244,952	-	-	-
Case A	95,531	61%	149,421	$ 974.37
Case B	73,486	70%	171,466	$1,282.91

Note that, when treated in this manner, there are no annual operating costs; thus the present value of cost for mobile sources will be just the capital cost and this will not change with changes in interest rates or the planning horizon. This is clearly not an accurate way in which to treat costs for this option but the treatment is adequate for purposes of this study. Moreover it overcomes problems associated with the direct use of MacLaren figures which do not lend themselves to a direct comparison with Senes cost data.

The "life time" figures assumed for development of scenarios in Chapter 4 are not related to any vehicle life time assumptions made by MacLarens.